COMMERCE DEPARTMENT

December 31, 2018 **PUBLIC DOCUMENT**

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-18-526

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, 2018 by:

> Amber S. Lee
> Regulatory and Legislative Affairs Manager
> Minnesota Energy Resources Corporation
> 2685 145th Street West
> Rosemount, MN 55068

On November 1, 2018, MERC submitted its November Supplemental Filing (Supplement). The Supplement was filed by:

> Seth DeMerritt
> Project Specialist 3
> Minnesota Energy Resources Corporation
> 2685 145th Street West
> Rosemount, MN 55068

Based on its review, the Department recommends that the Minnesota Public Utilities Commission (Commission):

- **Accept** the Company's proposed level of demand entitlement; and
- **Allow** MERC to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2018.

The Department also 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 Commission may have on this matter.

Sincerely,

/s/ ADAM J. HEINEN
Rates Analyst

AJH/jl
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G011/M-18-526

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, 2018 with the Minnesota Public Utilities Commission (Commission) to change the levels of demand for natural gas pipeline capacity (Petition) for is customers served by the Northern Natural Gas (NNG or Northern) System. MERC requested that the Commission approve changes in the Company's recovery of the overall level of contracted capacity.

On November 1, 2018, MERC made its November Supplemental Filing (Supplement) detailing final entitlement levels for the upcoming heating season. The Supplement includes final updated demand rates and anticipated commodity pricing. The Company did not update its total entitlement level, but the Supplement does reflect updated final future contracts, storage positions, and call options for the 2018-2019 heating season.

Using a similar design-day calculation methodology as has been used in the past, MERC proposed to increase its total design day by approximately 2.26 percent. In terms of capacity, MERC proposed to increase its entitlement level by 10,939 Dekatherms (Dkt)/day over the level in place last heating season, resulting in an estimated reserve margin of approximately 1.25 percent. This is a noticeable improvement over the negative reserve margin proposed by the Company in its previous demand entitlement, but it remains, at a relatively low level. In its last demand entitlement filing, MERC made changes to its Firm Deferred Delivery (FDD) storage contracts. The Company proposed no changes to these non-design-day deliverable contracts.

MERC's proposed entitlement changes result in an estimated increase in rates for residential customers of $0.2139 per Dkt or approximately $18.89 per year for customers assuming an annual usage of 88 Dkt.

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

The Minnesota Department of Commerce, Division of Energy Resources (Department) provides the following detailed analysis of the Company's Petition and its impact on MERC's rates and ratepayers. The Department's analysis of the Company's request includes the following areas:

- Rochester Project compliance;
- changes to capacity;
- design-day requirements;
- reserve margins;
- planning and integration; and
- PGA cost recovery proposals.

A. ROCHESTER PROJECT COMPLIANCE

In its May 8, 2018 Order in Docket No. G011/M-15-895, the Commission required MERC to provide semi-annual updates regarding capacity release associated with the Rochester Project and a discussion of each capacity substitution in its annual demand entitlement filing on a going-forward basis.

MERC provided information regarding this compliance requirement in its Petition. The Company explained that the first tranche of additional capacity associated with the Rochester Project became available on November 1, 2018. Since this first tranche of capacity increased the reserve margin to 1.25 percent, which remains below the 5 to 7 percent reserve margin target generally discussed by the Commission, the Company did not engage in capacity release for the 2018-2019 heating season. MERC also explained that, with respect to capacity substitution, it was able to add the communities of Balaton and Esko without paying for additional capacity because of the Rochester Project related capacity.[1]

The Department reviewed the Company's discussion regarding these compliance requirements and concludes that MERC complied with the Commission's May 8, 2018 Order.

B. MERC'S PROPOSED CHANGES

1. Changes to the Entitlement Level

As an initial matter, the Department confirms that, as required by the Commission's Order Point 9 of its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and

[1] Petition, Pages 8-9.

G011/M-15-724, MERC provided separate data on its summer and winter demand entitlements.

Table 1: MERC's Total Entitlement Levels

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
266,317	277,256	10,939	4.11

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

Contract Type	Previous Entitlement Level (Dkt)	Proposed Entitlement Level (Dkt)	Proposed Change in Entitlement (Dkt)
TFX-12	32,297	48,236	15,939
TFX-5	109,501	104,501	(5,000)

In regards to Northern 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). 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 Northern capacity year-over-year. The Company detailed its final TF-12B/V allocation in its Supplemental Filing. The update is detailed in Table 3 below.

Table 3: TF-12 Base and Variable Reallocation

Contract Type	Previous Entitlement Level (Dkt)	Proposed Entitlement Level (Dkt)	Proposed Change in Entitlement (Dkt)
TF-12 (Base)	49,219	46,506	(2,713)
TF-12 (Variable)	30,290	33,003	2,713

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

2. Changes to Non-Capacity Items

MERC did not propose changes to its non-capacity items in this demand entitlement filing. The Department notes that storage can be used as part of an integrated hedging plan to reduce baseload winter gas purchases and potentially lower the number of hedging instruments.

C. DESIGN-DAY REQUIREMENTS

As indicated in Department Attachment 1, the Company proposed to increase its total design day in Dkt as follows:

Table 4: MERC's NNG Design Day Levels

Previous Design Day (Dkt)	Proposed Design Day (Dkt)	Design Day Changes (Dkt)	Change From Previous Year
267,783	273,842	6,059	2.26%

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 estimates peak-day impact from interruptible customers in the Company's former MERC-NNG PGA service area save for the former MERC-Albert Lea service area.

In 2014, MERC purchased the Albert Lea service territory from Interstate Power and Light (IPL). At the time of the purchase, IPL had not installed telemetry for its interruptible customers. 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 customers in the new consolidated (MERC-NNG and MERC-Albert Lea), NNG PGA area. The Department and MERC worked together in past demand entitlement filings and reached an agreement on an appropriate design-day method. In last year's demand entitlement filing, MERC explained that it completed installation of telemetry for its former MERC-Albert Lea customers and anticipated having sufficient data for these customers in approximately two years to use in MERC's design-day analysis. As such, MERC continues to estimate the impact of interruptible customer consumption for the former IPL service territory. The Company estimated non-firm consumption based on an analysis of daily transport, interruptible, and joint interruptible throughput data and daily weather data. After estimating non-firm sales for the former Albert Lea PGA, the Company subtracted these estimates from total throughput data for this area to determine historical firm consumption.

After estimating daily firm data for the former Albert Lea PGA area, MERC had daily firm data in the correct format to estimate peak-day consumption. The design-day analysis employed by MERC, as described in the Petition, is similar to what was used by the Company in recent demand entitlement filings. The Company's design-day analysis is based on Ordinary Least Squares (OLS) regression and daily heating season (December, January, February) data over the period from December 2014 to February 2018. Given the disparate nature of the Company's service territory, it conducted five separate regression models for the various parts of the Northern PGA area. MERC used Adjusted Heating Degree Days (AHDD)[2] and various other determinants (e.g., month, day of the week, holiday) to estimate daily heating season consumption for each weather station area. The Department reviewed each of MERC's design-day regression models, and concluded that the signs on the coefficients are appropriate and the scale of the coefficients appear to be reasonable. The Department also notes that the Commission required MERC in past demand entitlement orders to verify and make various necessary adjustments to its regression analysis. The Department reviewed the Company's models and supporting information and confirms that MERC complied with the Commission's various orders.

The Company's planning objective is based on the coldest day in AHDD for each of MERC's regression models. For each of the regression models, the planning objective did not occur during the data period (2014 through 2018); as such, MERC adjusted the results to approximate usage at the planning objective. The Company's combined regression analyses resulted in a design-day estimate of 261,634 Dkt/day; however, as explained in MERC's filing, MERC modified the analysis such that the ultimate design-day estimate was based on the upper-bound of its regression analysis after factoring in a volume risk adjustment. This adjustment resulted in a calculated design-day estimate of 273,842 Dkt/day, which is 6,059 Dkt/day greater than the design-day estimate in last year's demand entitlement filing. The Company stated the volume risk adjustments were incorporated into the forecast to provide a confidence level that the daily metered load under design conditions would not exceed the daily metered regression estimate.[3] In other words, the volume risk adjustment is meant to modify the results to ensure a bias toward reliability since this adjustment places the design-day estimate at the top end of expected design-day conditions based on the regressions. This post-regression adjustment is similar to what the Company used in previous demand entitlement filings.

The Department reviewed MERC's analysis and was able to replicate the Company's results. In addition to this review, the Department conducted additional analysis to determine whether MERC's peak-day calculations were reasonable. First, the Department observed that the

[2] AHDD incorporates the impacts of wind into the weather determinant used to estimate peak day consumption. MERC has historically used AHDD in its design-day analysis.
[3] Petition, Attachment 12.

Company's regression results do not exhibit a bias either toward under-estimating or over-estimating daily historical consumption; namely, there is an equal distribution between days where the model results were above actual consumption and below actual consumption.[4] This is the expected result if a regression analysis is unbiased from a results perspective.

Second, using the regression coefficients from the Company's design-day models, the Department determined that firm throughput would have been approximately 257,909 Dkt on last heating season's peak day if the average temperature was at the planning objective.[5] This estimated firm throughput is 2,608 Dkt, or 1.02 percent, greater than the regression-estimated design-day figure of 255,301 Dkt calculated in last year's demand entitlement filing. This result suggests that MERC was short capacity during the previous heating season; however, the estimated firm throughput does not reflect the Company's volume risk adjustment. When the volume risk adjustment is applied to the estimated design-day figure of 255,201 Dkt, the estimated firm throughput of 257,909 Dkt is 9,874 Dkt, or 3.83 percent, lower than the adjusted estimate of 267,783 Dkt used by the Company to determine its total entitlement level (*i.e.,* actual planning threshold) in last year's demand entitlement filing. This analysis suggests that MERC's approach to calculating its design-day is likely sufficient to ensure reliability.

Third, the Department reviewed historical weather and throughput data for dates in which the average temperature was below zero (65 AHDD) to ascertain whether the coefficients from the Company's regressions adequately estimated actual historical usage.[6] Based on this review, the Department determined that the Company's model coefficients and results did not exhibit bias toward over- or under-estimating sales on a peak day.

Based on these analyses, the Department recommends that the Commission approve the Company's peak-day analysis.

D. RESERVE MARGIN

As indicated in Department Attachment 1, the proposed reserve margin is 3,414 Dkt, or 1.25 percent, as follows:

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[4] **Trade Secret** Department Attachment 2.

[5] The peak day on the Northern system occurred on December 31, 2017 last heating season. The calculation is as follows: Minneapolis-St. Paul [75,930 Dkt] + Cloquet [35,183 Dkt] + Albert Lea [15,578 Dkt] + Rochester [104,235] + Worthington [26,983 Dkt] = 257,909 Dkt.

[6] **Trade Secret** Department Attachment 2.

Table 5: MERC-Northern Reserve Margin

Total Entitlement (Dkt)	Design-Day Estimate (Dkt)	Difference (Dkt)	Reserve Margin (%)	Percentage Point Change From Prior Year
277,256	273,842	3,414	1.25%	1.88%

The proposed reserve margin of 1.25 percent represents an increase of 1.88 percentage points as compared to last year's reserve margin of (0.55) percent. The Company's proposed reserve margin is relatively low, but it represents an improvement over the negative reserve margin in last year's demand entitlement filing. Based on the Department's review of MERC's historic design-day data and regression results, the Department concludes that MERC's reserve margin is likely acceptable in terms of ensuring firm reliability on a peak day. However, the proposed reserve margin is at the lower end of acceptable reserve margins. The Department will continue to monitor this in future demand entitlement filings.

E. PLANNING AND INTEGRATION

In discussions before the Commission related to previous demand entitlement filings, the Commission expressed some concern regarding the reliability of the natural gas distribution system in light of increased use of natural gas for electric generation. The Commission also expressed concern regarding the lack of uniformity between reserve margins for different natural gas utilities and opined as to whether a standard reserve calculation or planning objective was possible or an improvement over the current system. Based on these concerns, and Minnesota's efforts to expand natural gas use in under- and unserved areas, there is a growing need to more closely examine reserve margins and to integrate natural gas supply planning with electric resource planning.

Before presenting the Department's analysis, it is worthwhile to illustrate the general differences between peak planning for the electric utilities and peak and general system planning[7] for natural gas utilities.

1. Industry Differences Impacting Reserve Margin Calculations

The primary difference is that the electric industry is necessarily more interdependent than the natural gas industry. A vertically integrated electricity provider supplies most of its own

[7] In addition to planning for peak days, natural gas utilities also procure pipeline supply considering minimum demand. Minimum usage (minimum day load) on a winter day is estimated to ensure that the 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.

product (through owned generation or purchased power agreements) and also relies on the non-contractual market [for Minnesota, the Midcontinent Independent System Operator (MISO)] at times when demand exceeds planned levels or outages prevent supply at the planned levels. Thus, the electric industry structure requires interdependency among market participants, necessitating a common, MISO system-wide reserve margin to ensure balanced reliance on the larger MISO system.

In contrast, 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 major factor impacting the level of interdependency within the electricity and natural gas industries is the greater availability of storage options for natural gas as opposed to electricity. For example, if natural gas utilities transmission pipeline companies 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.

As a result of the lack of interdependency between natural gas utilities, there is not a real-time energy market or independent system operator to dispatch resources, as there is in the electric industry. Although it is true that a third-party market (*i.e.,* capacity release) exists in the natural gas market, it does not work in the same way as the electric energy markets. First, the capacity release market is not in real-time, it requires lead-time and coordination between two utilities or an Electronic Bulletin Board (EBB) system (*e.g.,* auction) operated by the interstate pipeline.

Second, the nature of the capacity release market also makes a regional reserve margin less ideal because of the potential for cross-subsidies. Since the capacity release market, either on a short-term or long-term basis, is auction based, the utility that initially purchased the capacity is unlikely to receive full value for the capacity. As such, in a situation where one regional utility may be long on capacity and a second utility is short on capacity on a peak day, it is likely that the utility, and its ratepayers, that appropriately planned for a peak day will subsidize the utility with insufficient capacity. There is also the potential of a moral hazard because utilities may have an incentive to procure less capacity, to achieve lower rates in general, under the assumption that they can buy lower priced, released capacity when needed. Due to the need for individual gas utilities to procure sufficient, not too much and not too little, capacity to serve firm customers, reserve margins on the natural gas system are utility-specific rather than region-specific (as they are for the electric system).

Natural gas reserve margins are not only utility-specific, but it is possible for a natural gas utility to have different levels of reserve margins in different places on its system. That is, it may be misleading to consider a single utility-specific reserve margin as an accurate reflection of 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.) In addition, as noted in Section II.C above, the natural gas reserve margin can also be set based on statistical results.

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 or at the location 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.

2. Adequacy of MERC's Past Entitlement Levels

In light of these differences in peak planning for the electric utilities versus natural gas utilities, the Department gathered detailed information from MERC, and other natural gas utilities, in order to ascertain the number, timing, and cause of interruptions (curtailments), as a first step in assessing whether the demand entitlements procured, including reserve margins in place at those times, were sufficient and prudent. These data will also aid in monitoring the growing inter-relationship between the natural gas and electric industries.

Through discovery in various dockets, MERC provided the Department with daily throughput data (both firm and interruptible), curtailment data, and Maximum Daily Quantity (MDQ) data,[8] by TBS over the period from November 2012 to March 2018. Through an initial analysis, the Department observed that the data were presented in a manner that made linking the various components together difficult. The Department raised this concern with MERC and it was subsequently corrected; however, the Department did not receive these updated data in sufficient time to incorporate an analysis into these Comments. The Department will provide further review in subsequent supplemental comments. In particular, since the adequacy of entitlements to meet peak natural gas consumption, including possible impacts on energy system reliability, is focused on the heating season, the Department will likely concentrate its analysis on the heating season months (*i.e.,* November through March) and, in particular, the yearly peak sendouts on the Company's system since the 2012-2013 heating season.

The data provided thus far by the Company is at the TBS level. This specific, micro-level data can provide the Commission with significant insight into how MERC plans its system on both a system-wide and community or customer-specific level. Therefore, the Department recommends that MERC elaborate in detail, in its Reply Comments, how the Company conducts planning at a TBS level as well as what steps it takes to maintain reliability at the TBS level and to correct instances where consumption exceeds the MDQ.

3. Natural Gas Used to Generate Electricity

From the perspective of the natural gas system, interruptible service for electric generation customers is preferred because these generators are large and can have volatile consumption patterns especially during adverse weather conditions. From the natural gas utility's perspective, serving most electric generators under interruptible service is the most appropriate method to ensure firm natural gas reliability on a peak day. Under interruptible service, the gas utility is able to interrupt service to these customers, in either full or in part, such that traditional firm customers maintain service on a peak day.

From the perspective of electric reliability, however, firm service provides the greatest reliability since the fuel source is always available. Therefore, those generating facilities with

[8] The MDQ, or Maximum Daily Quantity, is the maximum volume amount that may be transported on a daily basis to a given receipt point or TBS based on an agreed-upon contract.

interruptible service potentially harm electric service reliability and/or cost[9] because these generating units may be unavailable when called on by MISO based on economic dispatch.[10]

As noted above, the Department did not receive updated TBS level data in sufficient time to incorporate these data into its analysis. Without these updated data, the Department was unable to analyze consumption by electric generators on the MERC system. The Department will analyze these data and provide additional analysis in future comments. In an effort to aid this analysis, the Department requests that MERC provide in Reply Comments the number of electric generators served, the annual Dkts consumed from 2014 through 2018, the TBS identifier for each plant, and the tariff under which each takes service.

F. THE COMPANY'S PGA COST RECOVERY PROPOSAL

In its Attachment 3, the Department compares MERC's October 2018 PGA to MERC's projected November 2018 PGA rates to highlight the changes in demand costs. The Department reviewed the Company's schedules and notes that the demand cost rate for October 2018 included in the Company's Supplemental, Attachment 4 does not match the demand charge per therm included in MERC's October 2018 PGA. The Department provides a corrected schedule in Department Attachment 3. According to the Department's calculations, the Company's demand entitlement proposal would result in the following annual demand cost impacts:

- annual bill increase of $18.83 related to demand costs, or 22.93 percent, for the average General Service customer consuming 88 Dth annually;
- annual bill increase of $160.45 related to demand costs, or 22.93 percent for the average Small Volume Firm customer consuming 5,110 Dth annually;
- annual bill increase of $481.34 related to demand costs, or 22.93 percent, 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.

The increase in demand costs are driven by the start of MERC's Rochester-specific demand charges. The Department notes that these charges are at a level significantly higher than typical maximum rates on the Northern system. These higher reservation rates are driven by the nature of the expansion on Northern's system. Since the costs associated with this contract, and the necessary upgrades to the Northern system, are specific to MERC and designed to benefit the Company, the entire cost of the project is assigned to MERC. If this

[9] The Department has not compared the cost savings from the cheaper interruptible service to the cost increase that may be incurred by the electric system due to the unavailability of natural gas.
[10] MISO does not factor in the deliverability of fuel when determining dispatch.

project provided benefit to the Northern system as a whole, it would be included in Northern's FERC-approved rates and assessed to all utilities through existing FERC-approved tariffs. Despite the higher costs, the Department notes that the Rochester Project was approved in Docket No. G011/M-15-895, and the Department concludes that the increased costs are reasonable and the associated entitlements are necessary to ensure system reliability. In addition, if the Rochester Project was not constructed, it is likely that MERC would have needed to procure other demand contracts, resulting in an increase in demand costs relative to the last demand entitlement filing.

Based on its analysis, the Department recommends that the Commission approve the proposed demand costs with an effective date of November 1, 2018.

III. THE DEPARTMENT'S RECOMMENDATIONS

Based on its review, the Department recommends that the Commission:

- **Accept** the Company's proposed level of demand entitlement; and
- **Allow** MERC to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2018.

The Department also requests that MERC provide in Reply Comments:

- a detailed discussion of how the Company conducts planning at the TBS level as well as what steps it takes to maintain reliability at the TBS level and to correct instances where consumption exceeds the MDQ; and
- the number of electric generators served, the annual Dkts consumed from 2014 through 2018, the TBS identifier for each plant, and the tariff under which each takes service.

The Department will offer additional comments and recommendations in subsequent response comments after it has reviewed the additional information.

/jl
Attachment

Department Attachment 1
Docket No. G011/M-18-526
MERC NNG Demand Entitlement Analysis*

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve (7) - (4)	% Reserve [(7)-(4)]/(4)
2018-2019	198,628	11,434	6.11%	273,842	7,017	2.63%	277,256	10,939	4.11%	3,414	1.25%
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			1.57%			1.94%			1.02%		5.86%

	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)
2018-2019	unknown			0.0172	1.3787	1.3959	unknown
2017-2018	233,945	21,292	10.01%	-0.0027	1.4254	1.4227	1.2497
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			2.65%	0.0767	1.3516	1.4282	1.1615

*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

TRADE SECRET DATA---ATTACHMENT EXCISED
IN ITS ENTIRETY

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2018

All costs in $/Dth	Base Cost of Gas G011/MR-17-564 Jan 1, 2018	Demand Charge Oct 1, 2017	Demand Charge Demand Filing Nov 1, 2017	Most Recent PGA Oct 1, 2018	Proposed Effective Nov 1, 2018	Result of Proposed Change: Change from Last Rate Case	Change from Nov 1, 2017 Demand Filing	Change from Last PGA %	Change from Last PGA $
1) General Service Residential: Avg. Annual Use:		**88**		**Dth**					
Commodity Cost	$3.7406	$3.2257	$3.0201	$3.9591	$3.9591	$0.2185	$0.9390	0.00%	$0.0000
Demand Cost	$0.9361	$0.9288	$0.9328	$0.9328	$1.1467	$0.2106	$0.2139	22.93%	$0.2139
Commodity Margin	$2.6284	$2.4116	$2.4116	$2.5727	$2.5727	($0.0557)	$0.1611	0.00%	$0.0000
Total Cost of Gas	$7.3051	$6.5661	$6.3645	$7.4646	$7.6785	$0.3734	$1.3140	2.87%	$0.2139
Avg Annual Cost	$642.85	$577.82	$560.08	$656.88	$675.71	$32.86	$115.63	2.87%	$18.83
Effect of proposed commodity change on average annual bills:									$0.00
Effect of proposed demand change on average annual bills:									$18.83
2) Small Vol. Interruptible: Avg. Annual Use:		**5,110**		**Dth**					
Commodity Cost	$3.7406	$3.2257	$3.0201	$3.8855	$3.9591	$0.2185	$0.9390	1.89%	$0.0736
Demand Cost									
Commodity Margin	$1.0616	$0.9740	$0.9740	$1.0391	$1.0391	($0.0225)	$0.0651	0.00%	$0.0000
Total Cost of Gas	$4.8022	$4.1997	$3.9941	$4.9246	$4.9982	$0.1960	$1.0041	1.49%	$0.0736
Avg Annual Cost	$24,539.24	$21,460.47	$20,409.85	$25,164.71	$25,540.80	$1,001.56	$5,130.95	1.49%	$376.10
Effect of proposed commodity change on average annual bills:									$376.10
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**16,150**		**Dth**					
Commodity Cost	$3.7406	$3.2257	$3.0201	$3.8855	$3.9591	$0.2185	$0.9390	1.89%	$0.0736
Demand Cost									
Commodity Margin	$0.5808	$0.5329	$0.5329	$0.5685	$0.5685	($0.0123)	$0.0356	0.00%	$0.0000
Total Cost of Gas	$4.3214	$3.7586	$3.5530	$4.4540	$4.5276	$0.2062	$0.9746	1.65%	$0.0736
Avg Annual Cost	$69,790.61	$60,701.39	$57,380.95	$71,932.10	$73,120.74	$3,330.13	$15,739.79	1.65%	$1,188.64
Effect of proposed commodity change on average annual bills:									$1,188.64
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**5,110**		**Dth**					
		25		**DTh**					
Commodity Cost	$3.7406	$3.2257	$3.0201	$3.8855	$3.9591	$0.2185	$0.9390	1.89%	$0.0736
Demand Cost	$28.0830	$27.8640	$27.98	$27.98	$34.4019	$0.0000	$6.4179	22.93%	$6.4179
Commodity Margin	$1.0616	$0.9740	$0.9740	$1.0391	$1.0391	($0.0225)	$0.0651	0.00%	$0.0000
Demand Margin	$3.2697	$3.0000	$3.0000	$3.1449	$3.1449	$3.1449	$0.1449	0.00%	$0.0000
Total Cost of Gas	$4.8022	$4.1997	$3.9941	$4.9246	$4.9982	$0.1960	$1.0041	1.49%	$0.0736
Total Demand Cost	$31.3527	$30.8640	$30.9840	$31.1289	$37.5468	$6.1941	$6.5628	20.62%	$6.4179
Avg Annual Cost	$25,323.06	$22,232.07	$21,184.45	$25,942.93	$26,479.47	$1,156.41	$5,295.02	2.07%	$536.54
Effect of proposed commodity change on average annual bills:									$376.10
Effect of proposed demand change on average annual bills:									$160.45
5) Large Vol. Firm: Avg. Annual Use:		**16,150**		**Dth**					
		75		**DTh**					
Commodity Cost	$3.7406	$3.2257	$3.0201	$3.8855	$3.9591	$0.2185	$0.9390	1.89%	$0.0736
Demand Cost	$28.0830	$27.8640	$27.9840	$27.9840	$34.4019	$6.3189	$6.4179	22.93%	$6.4179
Commodity Margin	$0.5808	$0.5329	$0.5329	$0.5685	$0.5685	($0.0123)	$0.0356	0.00%	$0.0000
Demand Margin	$3.2697	$3.0000	$3.0000	$3.1449	$3.1449	$0.0000	$0.1449	0.00%	$0.0000
Total Cost of Gas	$4.3214	$3.7586	$3.5530	$4.4540	$4.5276	$0.2062	$0.9746	1.65%	$0.0736
Total Demand Cost	$31.3527	$30.8640	$30.9840	$31.1289	$37.5468	$37.5468	$6.5628	20.62%	$6.4179
Avg Annual Cost	$72,142.06	$63,016.19	$59,704.75	$74,266.77	$75,936.75	$6,146.14	$16,232.00	2.25%	$1,669.98
Effect of proposed commodity change on average annual bills:									$1,188.64
Effect of proposed demand change on average annual bills:									$481.34

Note: Average Annual Average based on NNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-17-493

Note: Commodity Cost Rates do not include ACA adjustment.