December 31, 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-18-527

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 Consolidated System.

The Petition was filed on August 1, 2018 by:

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

On November 1, 2018, MERC submitted its *November Update* (Update). The Update was filed by:

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

The Department recommends the Minnesota Public Utilities Commission (Commission) approve MERC's *Petition*. The Department requests that MERC provide additional information in *Reply Comments*. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ DANIEL W. BECKETT
Rates Analyst

DWB/jl
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G011/M-18-527

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 for its customers served off the Consolidated Purchased Gas Adjustment (PGA) system (MERC-Consolidated). MERC requested that the Commission approve changes in the Company's recovery of its overall level of contracted capacity.[1] MERC-Consolidated serves customers located along three pipelines: Great Lakes Gas Transmission (Great Lakes or GLGT), Viking Gas Transmission Co. (Viking or VGT), and Centra Minnesota Pipelines (Centra).

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

In terms of capacity, MERC proposed to increase its Consolidated design-day requirement by 204 Dkt/day over the level in place last heating season. Using a similar design-day calculation methodology as has been used in the past, MERC proposed to increase its total design day requirement by 0.36 percent. Based on its design-day analysis and subsequent entitlement procurement strategy, the Company projected a 2.62 percent reserve margin for the upcoming heating season.

MERC's proposed entitlement changes result in an estimated increase in rates for residential customers of $0.1321 per Dth, or approximately $11.36 per year for General Service customers, assuming an annual usage of 86 Dth.

[1] MERC noted in its August cover letter that any updated information would be provided with the Company's November 1, 2018 filing.

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:

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

A. 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[2] 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.[3]

As indicated in Table 1 below, and Department Attachments 1 and 2, MERC's capacity purchases for the 2018-2019 heating season reflect no change in its total entitlement level, as follows:

Table 1: MERC-Consolidated Total Entitlement Levels

November 1, 2018 Filing	2017-2018 Entitlement (Dth)	2018-2019 Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
Centra	9,500	9,500	0	0.00%
Great Lakes	31,358	31,358	0	0.00%
Viking	17,091	17,091	0	0.00 %
Total Consolidated	57,949	57,949	0	0.00%

[2] 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."
[3] See MERC Attachment 3.

The Company stated that there are no changes to the level of capacity procured and that it will maintain the same deliverability levels as in 2017-2018.[4]

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

2. Changes to Non-Capacity Items

MERC entered into a four-year natural gas storage contract with ANR Pipeline Storage effective April 1, 2018. This contract replaces the Company's previous contract for storage with Niska Gas Storage. MERC requested approval of this contract on January 8, 2018, in Docket No. G011/M-17-587, and was granted approval by the Commission in its Order dated May 25, 2018.

Additionally, in its November 1, 2018 Supplement, the Company stated that it entered into a four-year contract with ANR Pipeline for the purposes of moving gas from ANR Storage to the interconnect with Great Lakes.

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-Consolidated Design-Day Levels

November 1, 2018 Filing	Previous Design Day (Dkt)	Proposed Design Day (Dkt)	Design Day Changes (Dkt)	% Change From Previous Year
Centra	8,928	9,137	209	2.34%
Great Lakes	30,457	30,186	(271)	(0.89)%
Viking	16,881	17,147	266	1.58%
Total Consolidated	56,266	56,470	204	0.36%

MERC used a similar approach to its design-day analysis as it used in last year's filing.[5] 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.

[4] *November 1, 2018 Update*, p. 5

[5] 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 MERC-Consolidated area.

Furthermore, MERC made the following adjustments to its data, as stated in its November 1, 2018 Update:[6]

> 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.

Beginning with its 2017 demand entitlement petition, MERC changed from identifying the coldest Adjusted Heating Degree Day (AHDD) in a rolling 20-year period (which, prior to 2017, included the historically cold weather in January/February 1996), to identifying the coldest AHDD for the time period January 1996-December 2016 for each weather station. Including the particularly cold 1996 data ensures that MERC does not under-estimate its capacity needs.

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.

The Department confirms that 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. RESERVE MARGIN

As indicated in Department Attachment 2, page 2, the proposed reserve margin is (1,479) Dth, or 2.62 percent, as follows:

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[6] *November 1, 2018 Update*, Attachment 12, p. 3.

Table 3: MERC-Consolidated Reserve Margin

November 1, 2018 Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	2018/2019 Reserve Margin %	2017/2018 Reserve Margin %	Percentage Point Change From Previous Year
Centra	9,500	9,137	363	3.97%	6.41%	(2.44)%
Great Lakes	31,358	30,186	1,172	3.88%	2.96%	0.92%
Viking	17,091	17,147	(56)	(0.32)%	1.24%	(1.56)%
Total Consolidated	57,949	56,470	1,479	2.62%	2.99%	(0.37)%

The proposed reserve margin of 2.62 percent represents a decrease of 0.37 percentage points as compared to last year's reserve margin of 2.99 percent.[7] The Company's proposed reserve margin is close to its 5-year average of 2.92 percent. 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 acceptable in terms of ensuring firm reliability on a peak day.

D. 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 difference between peak planning for the electric utilities and peak and general system planning[8] for natural gas utilities.

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[7] MERC Attachment 3.

[8] 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.

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 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 electric and natural gas industries is the 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.

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 than 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 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 moral hazard as 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, 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,[9] 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 is specific, micro-level data that can provide the Commission with significant insight into how MERC plans its system both on 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. Where from the natural gas utility's perspective, serving most electric generators under interruptible service is the most appropriate method to ensure firm reliability on a peak day. Under interruptible service, the gas utility is able to interrupt service to these customers, either in 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, generating facilities with

[9] 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 can potentially harm electric service reliability and/or cost[10] because these generating units may be unavailable when called on by MISO based on economic dispatch.[11]

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 Dths consumed from 2014 – 2018, and the tariff under which each takes service.

E. 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. 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 $11.36 related to demand costs, or approximately 2.03 percent, for the average General Service customer consuming 86 Dth annually;
- annual bill increase of $82.30 related to demand costs, or approximately 2.34 percent, for the average Large General Service customer consuming 624 Dth annually; and
- no demand cost impacts related to MERC's Consolidated interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission approve MERC's Petition, as modified in its November *Update*. Additionally, the Department requests that MERC provide the following information:

- A detailed explanation of how the Company conducts planning at the TBS level, as well as what steps it takes to maintain reliability and to correct instances where consumption exceeds the MDQ; and

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[10] 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.
[11] MISO does not factor in the deliverability of fuel when determining dispatch.

- The number of electric generators served, annual Dths consumed from 2014 – 2018, and the tariff under which each takes service.

/jl
Attachment

Department Attachment 1
Docket No. G011/M-18-527
MERC Consolidated Demand Entitlement Historical and Current Proposal

					Estimated 11/1/18			
Great Lakes Gas Transmisssion	**Contract #**	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 Quantity (Mcf)	2018-2019 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
FT Western Zone annual	FT19131	10,130	10,130	10,130	0	(10,130)		
FT Western Zone annual	FT18528	9,000	9,000	9,000	9,000	0		
FT Western Zone (12) annual	FT17891 (12)	3,600	3,600	3,600	3,600	0		
FT Western Zone (5) winter	FT18528 (5)	3,728	3,728	3,728	3,728	0		
FT Western Zone (5) winter	FT19129 (5)	3,300	3,350	4,900	15,030	10,130		
ANR (5)*					15,000	15,000		
Total Great Lakes		**29,758**	**29,808**	**31,358**	**31,358**	**0**	**0.00%**	
Viking Gas Transmission								
FT-A Zone 1 - 1 annual	AF0012	12,493	12,493	15,591	15,591	0		
FT-A Zone 1 - 1 winter	AF0209	1,098	1,098	0	0	0		
FT-A Zone 1 - 1 annual	AF0102	2,000	2,000	0	0	0		
FA-A Zone 1 - 1 annual	AFXXXX	1,000	0	1,500	1,500	0		
Total Viking		**16,591**	**15,591**	**17,091**	**17,091**	**0**	**0.00%**	
Centra Transmission Holding/Centra Mn Pipelines								
Centra FT - 1 annual		9,100	9,500	9,500	9,500	0		
Total Centra		**9,100**	**9,500**	**9,500**	**9,500**	**0**	**0.00%**	
Total Entitlement		**55,449**	**54,899**	**57,949**	**57,949**	**0**	**0.00%**	**0.36%**
Total Annual Transportation		**47,323**	**46,723**	**49,321**	**39,191**	**(10,130)**	**-20.54%**	
Total Winter Only Transport		**8,126**	**8,176**	**8,628**	**18,758**	**10,130**	**117.41%**	
Percent of Winter Only Capacity		14.65%	14.89%	14.89%	32.37%			

Source: MERC's Attachments 3 & 7
* The Department notes that this contract is not for deliverability.

Department Attachment 2
Docket No. G011/M-18-527
MERC Consolidated 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	35,653	(312)	-0.87%	56,470	204	0.36%	57,949	0	0.00%	1,479	2.62%
2017-2018	35,965	466	1.31%	56,266	738	1.33%	57,949	3,050	5.56%	1,683	2.99%
2016-2017	35,499	700	2.01%	55,528	2,453	4.62%	54,899	(550)	-0.99%	(629)	-1.13%
2015-2016	34,799	402	1.17%	53,075	4,369	8.97%	55,449	3,990	7.75%	2,374	4.47%
2014-2015	34,397	390	1.15%	48,706	(1,342)	-2.68%	51,459	(1,500)	-2.83%	2,753	5.65%
2013-2014	34,007			50,048			52,959				
Average			0.95%			2.52%			1.90%		2.92%

	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			0.0415	1.5839	1.6254	unknown
2017-2018	46,438	(2,358)	-4.83%	0.0468	1.5645	1.6113	1.2912
2016-2017	48,796	6,117	14.33%	-0.0177	1.5642	1.5465	1.3746
2015-2016	42,679	(3,072)	-6.71%	0.0682	1.5252	1.5934	1.2264
2014-2015	45,751			0.0800	1.4160	1.4960	1.3301
Average			0.93%	0.0438	1.5307	1.5745	1.3056

Source: MERC's Attachment 1

Department Attachment 3
Docket No. G011/M-18-527
MERC Consolidated Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-17-564 1/1/18	Last Demand Change 11/1/2017	Most Recent PGA 10/1/2018	Proposed Demand Changes 11/1/2018	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.1575	$2.6791	$3.2575	$3.2575	3.17%	21.59%	0.00%	$0.0000
Demand Cost	$0.7415	$0.7996	$0.6908	$0.8229	10.98%	2.91%	19.12%	$0.1321
Commodity Margin	$2.6284	$2.4116	$2.5727	$2.5727	-2.12%	6.68%	0.00%	$0.0000
Total Cost of Gas	$6.5274	$5.8903	$6.5210	$6.6531	1.93%	12.95%	2.03%	$0.1321
Average Annual Use	86	86	86	86				
Average Annual Cost of Gas*	$561.36	$506.57	$560.81	$572.17	1.93%	12.95%	2.03%	$11.36

Large General Service	Base Cost of Gas Change G011/MR-17-564 1/1/18	Last Demand Change 11/1/2017	Most Recent PGA 10/1/2018	Proposed Demand Changes 11/1/2018	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.1575	$2.6791	$3.2575	$3.2575	3.17%	21.59%	0.00%	$0.0000
Demand Cost	$0.7415	$0.7996	$0.6908	$0.8229	10.98%	2.91%	19.12%	$0.1321
Commodity Margin	$1.6885	$1.8232	$1.6885	$1.6885	0.00%	-7.39%	0.00%	$0.0000
Total Cost of Gas	$5.5875	$5.3019	$5.6368	$5.7689	3.25%	8.81%	2.34%	$0.1321
Average Annual Use	623	623	623	623				
Average Annual Cost of Gas*	$3,481.01	$3,303.08	$3,511.73	$3,594.02	3.25%	8.81%	2.34%	$82.30

SV Interruptible Service	Base Cost of Gas Change G011/MR-17-564 1/1/18	Last Demand Change 11/1/2017	Most Recent PGA 10/1/2018	Proposed Demand Changes 11/1/2018	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.1575	$2.6791	$3.2575	$3.2575	3.17%	21.59%	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	$4.1315	$3.6127	$4.2315	$4.2315	2.42%	17.13%	0.00%	$0.0000
Average Annual Use	7,637	7,637	7,637	7,637				
Average Annual Cost of Gas*	$31,552.27	$27,590.19	$32,315.97	$32,315.97	2.42%	17.13%	0.00%	$0.00

LV Interruptible Service	Base Cost of Gas Change G011/MR-17-564 1/1/18	Last Demand Change 11/1/2017	Most Recent PGA 10/1/2018	Proposed Demand Changes 11/1/2018	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$3.1575	$2.6791	$3.2575	$3.2575	3.17%	21.59%	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	$3.6904	$3.1798	$3.7904	$3.7904	2.71%	19.20%	0.00%	$0.0000
Average Annual Use	71,526	71,526	71,526	71,526				
Average Annual Cost of Gas*	$263,959.55	$227,438.37	$271,112.15	$271,112.15	2.71%	19.20%	0.00%	$0.00

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	$0.0000	$0.1321	$0.1321	2.03%	$11.36
Large General Service	$0.0000	$0.1321	$0.1321	2.34%	$82.30
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

* 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-17-493.

CERTIFICATE OF SERVICE

I, Marcella Emeott, hereby certify that I have this day served copies of the following document on the attached list of persons by electronic filing, 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-18-527**

Dated this **31ST** day of **December 2018.**
/s/Marcella Emeott

____

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_18-527_M-18-527
Michael	Auger	N/A	U S Energy Services, Inc.	Suite 1200 605 Highway 169 N Minneapolis, MN 554416531	Paper Service	No	OFF_SL_18-527_M-18-527
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-527_M-18-527
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