COMMERCE DEPARTMENT

January 2, 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. G008/M-17-533

Dear Mr. Wolf:

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

CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas' (CenterPoint or the Company) Request for Change in Demand Units (Petition) and Supplemental Information (Supplemental Filing).

The Petition was filed on November 1, 2017 by:

Marie Doyle
Regulatory Services
CenterPoint Energy
505 Nicollet Mall
PO Box 59038
Minneapolis, MN 55459-0038

The Department recommends that the Minnesota Public Utilities Commission (Commission) **accept** the Company's proposed level of demand entitlement and allow CenterPoint to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2017. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ ADAM J. HEINEN
Rates Analyst

AJH/ja
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G008/M-17-533

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2,[1] CenterPoint Energy (CenterPoint, CPE, or the Company) filed a petition requesting a change in demand[2] units (Petition) on July 3, 2017. The demand entitlement levels reported in the original Petition were proposed as of July and were not the final level of pipeline capacity actually purchased. Because the natural gas heating season spans the five-month period from November through March, the Company has the ability to secure capacity up until November 1st each year. In addition, the Petition did not reflect Northern Natural Gas' (Northern or NNG) 2017-2018 reallocation of units between TF-12 Base and TF-12 Variable services.[3]

On November 1, 2017, the Company filed a Supplemental Filing to provide the final level of pipeline capacity actually purchased for the upcoming winter. The document also includes final updated demand rates and anticipated commodity pricing.

In its Petition, CenterPoint requested that the Minnesota Public Utilities Commission (Commission) approve an increase in the Company's overall level of contracted pipeline capacity. In the updated Supplemental Filing, CenterPoint added 54,227 Dkt[4] per day of winter entitlement and 30,962 Dkt per day of summer entitlement on the Northern Natural Gas (NNG) system. The Company also added 10,000 Dkt per day of winter entitlement on the Viking Gas Transmission (Viking or VGT) system. The breakout of the additional entitlement is listed below in Table 1.

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[1] ***Filing by Gas Utilities:*** *Filing upon a change in demand.* Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.
[2] Also called entitlement, capacity, or transportation on the pipeline.
[3] On November 1, NNG annually adjusts TF-12 Base and Variable billing unit entitlements based on the utility's gas use in the previous May-through-September period. The adjustments are in accordance with NNG's tariff approved by the Federal Energy Regulatory Commission (FERC).
[4] Dekatherms (Dkt or DT).

Table 1 – Demand Entitlement Changes

Pipeline Receipt Point	Pipeline Delivery Point	Discount or Non-Discount	Proposed Changes: Increase (Decrease) (Dkt)	
			5-month (Winter)	7-month (Summer)
NNG - Ventura	Anoka #1	Discount	2,166	1,091
NNG - Ventura	Anoka #1A	Discount	772	372
NNG - Ventura	Blaine #1	Discount	815	278
NNG - Ventura	Dayton #1	Discount	3,044	1,696
NNG - Ventura	Elk River #1	Discount	634	248
NNG - Ventura	Ham Lake #1	Discount	963	470
NNG - Ventura	Minneapolis #1D	Discount	16,000	9,117
NNG - Ventura	Mankato #1A	Discount	1,358	955
NNG - Ventura	Minneapolis #1Q	Discount	5,000	2,242
NNG - Ventura	Minneapolis #1P	Discount	9,576	4,546
NNG - Ventura	Belle Plaine #1	Non-Discount	275	161
NNG - Ventura	Eagle Lake #1	Non-Discount	1,000	617
NNG - Ventura	Elk River #1B	Non-Discount	1,000	533
NNG - Ventura	Jordan #2	Non-Discount	2,000	1,046
NNG - Ventura	New Prague #1	Non-Discount	2,000	1,302
NNG - Ventura	St. Peter #1	Non-Discount	2,500	1,636
NNG - Ventura	Willmar #1	Non-Discount	1,000	734
NNG - Welcome	Madelia	Non-Discount	221	221
NNG - Welcome	Springfield	Non-Discount	198	198
NNG - Welcome	Sleepy Eye	Non-Discount	162	162
NNG - Welcome	St. James	Non-Discount	19	19
NNG - Chisago	Grasston MN #1	Non-Discount	60	60
NNG - Chisago	Centerville MN #1	Non-Discount	27	27
NNG - Chisago	Hastings MN #1C	Non-Discount	1,512	1,512
NNG - Carlton	Hastings MN #1C	Non-Discount	283	283
NNG - Carlton	Coates MN #1	Non-Discount	500	500
NNG - Carlton	Hastings MN #1B	Non-Discount	202	202
NNG – Unspecified [5]	Unspecified Delivery Points	Non-Discount	940	734
Viking – Emerson	Pierz/Chisago	Not Applicable	10,000	
TOTAL			**64,227**	**30,962**

[5] CPE Supplemental Filing, Exhibit B3, Lines 36 and 37. The capacity additions were contracted in 2015 to be added effective November 1, 2017.

CenterPoint stated that entitlements were added based on the Company's evaluation of the needs on its distribution system and in support of forecasted customer growth.

The Company also reported in the Petition and Supplemental Filing that the propane peaking capacity would be decreasing by 22,000 Dth per day for the upcoming winter due to an engineering review of the aggregate delivery capability of the facilities.

Finally, CenterPoint made changes to the amount of storage contracted. Storage does not directly impact daily entitlements, but is an important tool to secure supply. In the Petition, the Company stated that it was able to add 3.3 Bcf of NNG Firm Deferred Delivery (FDD) storage service via an open season.

The effects of the changes listed above are shown in greater detail and compared to the prior filings in Department Attachment 1.

The changes as reflected in CenterPoint's Supplemental Filing result in an overall decrease in monthly Purchased Gas Adjustment (PGA) rates, as discussed below.

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

The Minnesota Department of Commerce, Division of Energy Resources' (Department) analysis of the Company's request includes the following sections:

- the proposed changes to the entitlement level and to non-capacity items;
- the design-day requirement;
- the reserve margins; and
- the PGA cost recovery proposals.

A. PROPOSED CHANGES

1. Changes to the Entitlement Level

As indicated in Department Attachment 1, the Company proposed to increase its total entitlement level from the prior year by 34,126 Dkt as follows:

Table 2 – CenterPoint's Total Entitlement Levels

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
1,375,470	1,409,596	34,126	2.48%

CenterPoint's increase to entitlement was largely attributed to the addition of pipeline capacity on NNG and Viking for the 2017-2018 heating season of 54,227 Dkt and 10,000 Dkt respectively. The Company's increase in pipeline capacity was partially offset by a decrease in propane peaking capacity of 22,200 Dkt. The Company also elected not to contract for any peaking service from a third-party gas supplier as was done in the prior heating season, for which CenterPoint contracted to receive 6,000 Dkt. CenterPoint confirmed in follow up discussion that it determined peaking service from gas suppliers was not needed once the addition of the 10,000 Dkt on Viking was secured.

Based on its analysis, the Department concludes that CenterPoint's proposed level of demand entitlement is reasonable. The Department recommends approval of the demand entitlement.

2. *Changes to Non-Capacity Items*

CenterPoint participated in an open season last winter in an effort to add NNG storage capacity. NNG offered 6.1 Bcf of available storage capacity in which CenterPoint bid on all the available capacity. The Company was awarded 2.8 Bcf of the capacity based on the bidding process and negotiated another 0.5 Bcf via a permanent release. Table 3 below illustrates the change in volume due to the changes in contracted storage.

Table 3 – CenterPoint Storage

Storage Contract	2016-17 Heating Season (Dkt)	2017-18 Heating Season (Dkt)	Year-Over-Year Change (Dkt)	Year-Over-Year Change (%)
Storage NGPL	210,986	210,986	-	0.00%
Marketer	120,000	120,000	-	0.00%
Storage NNG FDD	-	57,094	**57,094**	100.00%
Waterville	50,000	50,000	-	0.00%
Total	**380,986**	**438,080**	**57,094**	**14.99%**

The Company indicated that NNG storage capacity is rarely available and offered that the new capacity secured would have the following benefits:[6]

- NNG storage provides operational dependability and flexibility as a quick source of load-following gas supply when our customer's demand changes rapidly.

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[6] Petition, Page 3.

- NNG storage can also be used for monthly balancing of gas transported, eliminating potential cash-out fees.
- NNG storage reduces the amount of winter base load and daily swing gas that CenterPoint now purchases, creating gas cost reductions for customers.
- NNG storage does not incur additional upstream pipeline transport fees to move the stored gas to the distribution systems (this cost would be approximately $2 million annually on the NGPL system).

The Company's addition of NNG storage capacity appears reasonable and will cover 31 percent of the design day (438,040 Dkt/ 1,403,000 Dkt). The Department agrees 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.

As was done since the 2011 demand entitlement filings, CenterPoint zeroed out the Capacity Release and the Off-System Margin Sales credits. These items are adjusted on a monthly basis as credits become known.

3. *Design-Day Requirement*

a. *CPE Analysis*

The design-day analysis employed by CenterPoint in this filing is similar to what was used by the Company in recent demand entitlement filings. CenterPoint also employed a secondary regression analysis to account for the recent, and expected, migration of non-firm, dual fuel customers to firm service.

CenterPoint's traditional design-day analysis is based, in large part, on the work done in its supplemental filing in Docket No. G008/M-11-1078. The Company's design day analysis is based on Ordinary Least Squares (OLS) regression and daily heating season (November through March) data over the period from November 2011 to March 2017. CPE used heating degree days (HDDs) and the squared value of HDDs (HDD^2) to estimate daily firm use per customer (UPC). CPE used the same estimation period and model specifications for its existing customer model and new firm customer models, with the exception of modeling the secondary regression on the combined "new" firm group's consumption rather than on UPC, since the customer count was assumed to be static throughout the entire November 2011 to March 2017 period. The factor HDD^2 is included in the regression equation to account for non-linear relationships that may exist between HDDs and UPC. The inclusion of a squared HDD term is an appropriate method of accounting for non-linear relationships.

The Department reviewed CenterPoint's design day regression models, and concluded that the signs on HDD and HDD^2 are both positive and the scale of the coefficients appear to be reasonable.

As noted above, the Company conducted two separate regression models, one for existing firm customers and a second for new firm customers and those expected to transition to firm sales service during the heating season. The decision to use two regression models marks a departure from what the Company used in previous demand entitlement filings. To the extent sufficient data exist, CenterPoint's decision is reasonable and represents, in many respects, the most appropriate way to model design-day consumption. It is possible that these recent and soon-to-be transitioning customers have usage characteristics that are different than those of existing firm customers; therefore, if the Company used a single regression model and applied after-the-fact adjustments based on current firm usage, it is possible that peak day consumption estimates would be inaccurate and, potentially, under estimated. Since the results of the Company's customer transition model are acceptable, the Department concludes the CenterPoint's two-regression approach is reasonable at this time. The Department will continue to monitor this approach in future demand entitlement filings.

As noted earlier, the Company's analysis is based on daily throughput and weather data over the period from November 2011 to March 2017. CenterPoint'scombined analyses result in a design-day estimate of 1,291,975 Dkt/day;[7] however, as explained in the CPE's filing, the Company modified the analysis such that the ultimate design-day estimate was based on the upper bound of the regression output, which results in a calculated design day of 1,357,163 Dkt/day,[8] which is 29,163 Dkt/day greater than the design-day estimate in last year's demand entitlement filing.[9] The Company stated that it made this modification 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.

The peak-day process is complex and can be impacted by many different factors. Although weather (HDDs) is the driving factor behind peak-day use, the ultimate result is also dependent upon the day of the week and when during a cold spell the event occurs, among other things. CenterPoint's analysis only incorporates the impacts of weather and does not contemplate other factors including: day of the week, month, and heating season. In other words, CPE's analysis assumes that all days are equal. The impact of these other factors is unclear.

[7] 1,274,000 Dkt/day+17,975 Dkt/day = 1,291,975 Dkt/day. Exhibit B1.
[8] 1,338,000 Dkt/Day + 19,163 Dkt/day. Exhibit B1.
[9] In its Supplemental Filing, CenterPoint stated that its calculated design day increased from 1,357,163 Dkt/day to 1,367,163. CenterPoint Supplemental Filing Ex. B3, Page 2 of 2. The Department contacted CenterPoint and the Company confirmed that the figure presented in the Supplemental Filing was incorrect. There was no change in the calculated design day between the original and supplemental filings.

However, the Department conducted an alternative regression analysis to independently evaluate the impact of these other factors on CPE's design-day regressions as discussed further below.

b. Department's Alternative Design-Day Analysis

The Department conducted similar alternative analyses in recent CenterPoint demand entitlement filings to analyze the reasonableness of the Company's design-day estimates. The Department's alternative analysis was based on the same time period as CenterPoint's and included HDDs and HDD^2 along with factors that account for month, day of the week, and heating season. Including these additional factors was expected to provide additional explanatory precision to the analysis, if they are relevant, and isolate characteristics specific to each heating season day. The Department conducted its regression analysis and obtained consistent results (*e.g.,* positive signs on both HDD factors) that are similar to CPE's (Department Attachment 2). The Department identified the factors with the greatest impact, by type (*i.e.,* month, day of the week, heating season), and then added these values to the impacts related to baseload and weather.[10] This approach is conservative and should bias the calculation in the favor of system reliability. Using this alternative approach, the additional regression factors decrease the projected design day by a small amount, from CenterPoint's 1,291,975 Dkt/day figure to approximately 1,280,980 Dkt/day[11] as calculated using the Department's model. The Department's results are within the confidence interval from the Company's design-day analysis.

For comparative purposes, the Department also calculated a design-day based on the upper bound of its regression result. Using the upper bound, the Department's estimated design day, approximately 1,407,778,220 Dkt/day,[12] is greater than CenterPoint's proposed total entitlement level of 1,357,163 Dkt/day. Despite the Department's higher estimate, this result is lower than the Company's revised total capacity figure, inclusive of physical reserve, of 1,409,596 Dkt/day, which suggests that CenterPoint will likely have sufficient capacity to serve firm customers on a peak day. Although it appears that the Company has sufficient capacity to serve a peak day, the Department conducted additional analysis to further validate whether CenterPoint's peak-day calculations are reasonable.

[10] The Department notes that the factors with the greatest impact in its alternative analysis differ between the existing firm and transitioning firm customer models; as such, the design-day results are analogous to an estimate of non-coincident peak throughput. Therefore, because the two model results are added together and are based on different input characteristics, the Department's estimate likely has a bias toward over-estimating peak-day usage.

[11] 1.4766 UPC *855,362 customers = 1,262,998 Dkt/day [existing customer model] + 17,982 Dkt/day [transitioning customer model] = 1,280,980 Dkt/day. Department Attachment 2 and CenterPoint Exhibit B1.

[12] 1.6209 UPC *855,362 customers = 1,386,510 Dkt/day [existing customer model] + 21,268 Dkt/day [transitioning customer model] = 1,407,220 Dkt/day. Department Attachment 2 and CenterPoint Exhibit B1.

Using the regression coefficients from the Company's design-day models (Exhibit B1 of the Company's Petition), the Department determined that firm throughput would have been 1,238,956 Dkt on last heating season's peak day if the average temperature was 90 HDD. This result is 26,044 Dkt, or 2.1 percent, lower than the regression-estimated design-day figure of 1,265,000 Dkt calculated in last year's demand entitlement filing. In addition, this result is 89,044 Dkt, or 7.19 percent, lower than the upper-bound estimate used by the Company to determine its total entitlement level in last year's demand entitlement filing. This analysis reinforces the Department's conclusion that CenterPoint's approach to calculating its design-day is likely sufficient to ensure reliability.

The Department also conducted an after-the-fact analysis using its alternative calculations discussed above and CenterPoint's analysis. This is similar to an analysis the Department conducted in previous demand entitlement filings. The predicted sales for the 2016-2017 heating season peak day using the Department's alternative analysis suggests that the design-day models may have a slight bias toward under-estimating sales (874,374 Dkt/day estimated sales compared to actual sales of 993,410 Dkt/day). The predicted sales for the 2016-2017 heating season peak day using CenterPoint's analysis also suggests that the design-day models may have a slight bias toward under-estimating sales (916,570 Dkt/day estimated sales compared to actual sales of 993,410 Dkt/day). These results may suggest that the design-day models have a bias toward under-estimating sales on a peak day; however, it is important to note that last heating season's peak sendout occurred on a day much warmer (69.5 HDD) than the 90 HDD planning objective.[13] As such, it is unclear if the model would also have a bias toward under-estimation for an all-time peak day.

Based on its review of the Company's results, the Department's results, and the various areas of concern identified above, the Department concludes that CenterPoint's design-day analysis and assumptions are acceptable and appropriate for determining peak-day consumption for the upcoming heating season. Despite questions regarding whether the models have bias toward under-estimating firm sales on the coldest days, the Department's alternative upper bound estimate suggests that CenterPoint has sufficient capacity to ensure firm reliability on a peak day. Since CenterPoint and the Department used upper bound analyses, it is unlikely that firm reliability will be impaired on a peak day.

The Department will continue to monitor CenterPoint's method in future demand entitlement filings and recommends that the Commission accept the design-day level proposed by CPE in this proceeding. However, as discussed further below, the Department does conclude that the Company's proposed reserve margin likely represents the lowest figure that can ensure firm reliability on a peak day.

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[13] The peak sendout during the 2016-2017 heating season occurred on January 5, 2017 for both existing and new firm customers.

In oral discussion regarding CenterPoint's last demand entitlement filing, the Commission expressed concern with how natural gas utilities determine the appropriate reserve margin percentage. Specifically, the Commission noted that electric utilities have a standard planning reserve margin and inquired as to whether a standardized reserve margin, or reserve margin calculation, may be appropriate for Minnesota natural gas utilities. The Department further discusses this below in reserve margin section.

4. *Reserve Margin*

As shown below and in Department Attachment 3, CPE's proposed reserve margin is 0.47 percent:

Table 4 – CenterPoint Reserve Margin

Total Entitlement (Dkt)	**Design-Day Estimate (Dkt)**[14]	**Difference (Dkt)**	**Reserve Margin (%)**	**Percentage Point Change From Prior Year**
1,409,596	1,403,000	6,596	0.47%	(0.37)%
Total Entitlement (Dkt)	**Design-Day Estimate without physical reserve (Dkt)**	**Difference (Dkt)**	**Reserve Margin (%)**	**Percentage Point Change From Prior Year**
1,409,596	1,357,163	52,433	3.86%	3.02%

Both the total entitlement and design-day estimate increased when compared to the prior year. The entitlement increased 4,874 Dkt less than the design-day resulting in a 0.37 percentage point decrease in reserve margin when compared to the prior year. The Department notes that a 0.47 percent reserve margin is lower than the desired amount of reserve typically approved by the Commission.

It is worth noting that the Company modified the analysis such that the ultimate design-day estimate was based on the upper bound of the regression output. The Company stated that it made this modification 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 regression. As discussed above, the Department has concluded that this approach is reasonable, and that CenterPoint likely has sufficient capacity to serve needs on an all-time peak day even with the seemingly low reserve margin.

[14] "Design-Day Estimate" includes CenterPoint's calculated design day of 1,367,000 Dkt and the physical reserve of 36,000 as shown in Petition at pg. 4. If the physical reserve is removed, which essentially means the CenterPoint could use physical reserve to meet firm requirements, the Company's reserve margin is approximately 3.02%.

The Department also 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 Department Attachment 5. 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 Department Attachment 6) and has followed-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.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amount listed in Department Attachment 1 represents the demand entitlements for which the Company's firm customers will be paying beginning November 1, 2017. In its Petition, CenterPoint compared its October 2017 PGA rates to its proposed November 2017 PGA which resulted in a decrease of demand costs by $0.0025 per Dkt for the Residential class. As shown in Department Attachment 4, the Department also prepared this analysis and found the same result. CenterPoint's proposed changes would result in the following annual rate impacts:

- Annual demand cost decrease of $0.25, or approximately 0.31 percent, for the average Residential customer consuming 100 Dkt annually;
- Annual demand cost decrease of $0.20, or approximately 0.31 percent, for the average Commercial/Industrial Firm - A customer consuming 80 Dkt annually;
- Annual demand cost decrease of $7.15, or approximately 0.31 percent, for the average Commercial/Industrial Firm - B customer consuming 2,860 Dkt annually; and
- Annual demand cost decrease of $35.75, or approximately 0.31 percent, for the average Commercial/Industrial Firm - C customer consuming 14,300 Dkt annually.

The decrease in demand costs is driven by the change in the winter discount rate for multiple NNG contracts. In the 2016-2017 heating season, the per-unit winter rate increased to $9.013, mostly to fund the costs for construction to create additional entitlements. With the construction completed, the rate went back to $7.783 on November 1, 2017. Without the adjustment to the NNG winter contracts, demand cost on a per-unit basis would have increased because of the purchase of new pipeline and storage capacity discussed above in the entitlement section.

It is important to note that the total cost of gas increased for the November 2017 as compared to October 2017. This was driven by the commodity cost of gas difference between the two months. CenterPoint has a hedging strategy, but increases such as this one are driven by market forces and cannot be completely mitigated by the Company.

Based on its analysis, the Department recommends that the Commission approve the proposed demand costs with an effective date of November 1, 2017.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission:

- approve CenterPoint's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2017; and
- accept the design-day level proposed by CPE.

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Department Attachment 1
Docket No. G008/M-17-533
CenterPoint Demand Entitlement Historical and Current Proposal

Heating Season Services	(1) CenterPoint Energy 15-644 (July 2015) Quantity (Dkt)	(2) CenterPoint Energy 15-644 (Dec 2015) Quantity (Dkt)	(3) CenterPoint Energy 16-571 (July 2016) Quantity (Dkt)	(4) CenterPoint Energy 16-571 (Nov 2016) Quantity (Dkt)	(5) CenterPoint Energy 17-533 (July 2017) Quantity (Dkt)	(6) CenterPoint Energy 17-533 (Nov 2017) Quantity (Dkt)	(7) TOTAL Change (Nov. 2016 - Nov. 2017)
[TRADE SECRET DATA BEGINS							(6)-(4)
							TRADE SECRET DATA ENDS]
NNG Demand Winter	1,018,671	1,021,056	1,021,056	1,025,375	1,079,602	1,079,602	54,227
NNG /Viking Overlap	(24,914)	(24,914)	(24,914)	(24,914)	(26,815)	(26,815)	(1,901)
Total NNG Demand Winter	993,757	996,142	996,142	1,000,461	1,052,787	1,052,787	52,326
Total NNG Demand Summer	574,472	574,667	574,667	575,466	606,428	606,428	30,962
[TRADE SECRET DATA BEGINS							
							TRADE SECRET DATA ENDS]
Total Viking Demand	56,809	66,809	66,809	66,809	56,809	76,809	10,000
Trailblazer (FTS Backhaul)	100,000	100,000	100,000	100,000	100,000	100,000	0
Supply Demand							
[TRADE SECRET DATA BEGINS							
							TRADE SECRET DATA ENDS]
NOTE: Reflects total volumes contracted and does not reflect any cost allocation.							
Released Capacity	0	0	0	0	0	0	0
Peaking Service	0	0	0	6,000	10,000	0	
Underground Storage	50,000	50,000	50,000	50,000	50,000	50,000	0
LNG Peak Shaving	72,000	72,000	72,000	72,000	72,000	72,000	0
Propane Peak Shaving	171,000	171,000	180,200	180,200	158,000	158,000	(22,200)
Total Peaking	293,000	293,000	302,200	308,200	290,000	280,000	(28,200)
Total Capacity	1,343,566	1,355,951	1,365,151	1,375,470	1,399,596	1,409,596	34,126
Total Peak-Shaving Capacity/On-line Storage	293,000	293,000	302,200	308,200	290,000	280,000	(28,200)
Total Annual Transportation	631,281	631,476	631,476	632,275	663,237	663,237	30,962
Total Seasonal Transportation	1,050,566	1,062,951	1,062,951	1,067,270	1,109,596	1,129,596	62,326
Peak Shaving as % of Total Capacity	21.8%	21.6%	22.1%	22.4%	20.7%	19.9%	-2.5%
Annual Transportation as % of Total Capacity	47.0%	46.6%	46.3%	46.0%	47.4%	47.1%	1.1%
Seasonal Transportation as % of Total Capacity	78.2%	78.4%	77.9%	77.6%	79.3%	80.1%	2.5%
Annual and Seasonal Transportation as % of Total Transportation	62.5%	62.7%	62.7%	62.8%	62.6%	63.0%	0.2%

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20 . save "H:\CenterPoint M Dockets\G008-M-17-533\2017 Full Design Day.dta", replace
   file H:\CenterPoint M Dockets\G008-M-17-533\2017 Full Design Day.dta saved

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22 . regress upc hdd hdds_2 nov dec jan feb mar sun mon tue wed thu fri sat hs112 hs1213 hs1314 hs141
   > 5 hs1516 hs1617
   variable hdds_2 not found
   r(111);

23 . regress upc hdd HDDs_2 Nov Dec Jan Feb Mar Sun Mon Tue Wed Thu Fri Sat HS1112 HS1213 HS1314 HS14
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   note: Jan omitted because of collinearity
   note: Wed omitted because of collinearity
   note: HS1112 omitted because of collinearity

         Source |       SS       df       MS              Number of obs =     907
   -------------+------------------------------           F( 17,   889) = 3182.99
          Model |  49.5753159    17  2.91619505           Prob > F      =  0.0000
       Residual |  .81448484    889  .000916181           R-squared     =  0.9838
   -------------+------------------------------           Adj R-squared =  0.9835
          Total |  50.3898008   906  .055617882           Root MSE      =  .03027

   ------------------------------------------------------------------------------
            upc |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
   -------------+----------------------------------------------------------------
            hdd |   .0126235   .0002993    42.18   0.000     .0120361    .0132109
         HDDs_2 |   .0000292   3.57e-06     8.17   0.000     .0000222    .0000362
            Nov |  -.0551138   .0035561   -15.50   0.000    -.0620932   -.0481344
            Dec |  -.0240794   .0031864    -7.56   0.000     -.030333   -.0178257
            Jan |          0  (omitted)
            Feb |   -.014426   .0032321    -4.46   0.000    -.0207695   -.0080826
            Mar |  -.0344272   .0035008    -9.83   0.000    -.0412979   -.0275564
            Sun |  -.0012404   .0037667    -0.33   0.742    -.0086331    .0061523
            Mon |   .0014074   .0037804     0.37   0.710    -.0060122    .0088269
            Tue |    .002703   .0037627     0.72   0.473    -.0046817    .0100878
            Wed |          0  (omitted)
            Thu |  -.0032274   .0037635    -0.86   0.391    -.0106137     .004159
            Fri |   -.006483   .0037643    -1.72   0.085    -.0138708    .0009049
            Sat |  -.0135268    .003763    -3.59   0.000    -.0209122   -.0061414
         HS1112 |          0  (omitted)
         HS1213 |   .0016708   .0035681     0.47   0.640    -.0053321    .0086736
         HS1314 |   .0221806   .0037282     5.95   0.000     .0148635    .0294976
         HS1415 |    .025438   .0035809     7.10   0.000     .0184101     .032466
         hs1516 |   .0164517   .0034826     4.72   0.000     .0096166    .0232869
         hs1617 |   .0291271   .0034897     8.35   0.000     .0222781    .0359762
          _cons |   .0957192   .0072575    13.19   0.000     .0814754    .1099631
   ------------------------------------------------------------------------------

24 . regress upc hdd HDDs_2 Nov Dec Feb Mar Sun Mon Tue Thu Fri Sat HS1213 HS1314 HS1415 hs1516 hs161
   > 7

         Source |       SS       df       MS              Number of obs =     907
   -------------+------------------------------           F( 17,   889) = 3182.99
          Model |  49.5753159    17  2.91619505           Prob > F      =  0.0000
       Residual |  .81448484    889  .000916181           R-squared     =  0.9838
   -------------+------------------------------           Adj R-squared =  0.9835
          Total |  50.3898008   906  .055617882           Root MSE      =  .03027
```

upc	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
hdd	.0126235	.0002993	42.18	0.000	.0120361	.0132109
HDDs_2	.0000292	3.57e-06	8.17	0.000	.0000222	.0000362
Nov	-.0551138	.0035561	-15.50	0.000	-.0620932	-.0481344
Dec	-.0240794	.0031864	-7.56	0.000	-.030333	-.0178257
Feb	-.014426	.0032321	-4.46	0.000	-.0207695	-.0080826
Mar	-.0344272	.0035008	-9.83	0.000	-.0412979	-.0275564
Sun	-.0012404	.0037667	-0.33	0.742	-.0086331	.0061523
Mon	.0014074	.0037804	0.37	0.710	-.0060122	.0088269
Tue	.002703	.0037627	0.72	0.473	-.0046817	.0100878
Thu	-.0032274	.0037635	-0.86	0.391	-.0106137	.004159
Fri	-.006483	.0037643	-1.72	0.085	-.0138708	.0009049
Sat	-.0135268	.003763	-3.59	0.000	-.0209122	-.0061414
HS1213	.0016708	.0035681	0.47	0.640	-.0053321	.0086736
HS1314	.0221806	.0037282	5.95	0.000	.0148635	.0294976
HS1415	.025438	.0035809	7.10	0.000	.0184101	.032466
hs1516	.0164517	.0034826	4.72	0.000	.0096166	.0232869
hs1617	.0291271	.0034897	8.35	0.000	.0222781	.0359762
_cons	.0957192	.0072575	13.19	0.000	.0814754	.1099631

```
25 . regress upc hdd HDDs_2 Nov Dec Feb Mar Sun Mon Tue Thu Fri Sat HS1213 HS1314 HS1415 hs1516 hs161
> 7
```

Source	SS	df	MS
Model	49.5753159	17	2.91619505
Residual	.81448484	889	.000916181
Total	50.3898008	906	.055617882

Number of obs =	907
F(17, 889) =	3182.99
Prob > F =	0.0000
R-squared =	0.9838
Adj R-squared =	0.9835
Root MSE =	.03027

upc	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
hdd	.0126235	.0002993	42.18	0.000	.0120361	.0132109
HDDs_2	.0000292	3.57e-06	8.17	0.000	.0000222	.0000362
Nov	-.0551138	.0035561	-15.50	0.000	-.0620932	-.0481344
Dec	-.0240794	.0031864	-7.56	0.000	-.030333	-.0178257
Feb	-.014426	.0032321	-4.46	0.000	-.0207695	-.0080826
Mar	-.0344272	.0035008	-9.83	0.000	-.0412979	-.0275564
Sun	-.0012404	.0037667	-0.33	0.742	-.0086331	.0061523
Mon	.0014074	.0037804	0.37	0.710	-.0060122	.0088269
Tue	.002703	.0037627	0.72	0.473	-.0046817	.0100878
Thu	-.0032274	.0037635	-0.86	0.391	-.0106137	.004159
Fri	-.006483	.0037643	-1.72	0.085	-.0138708	.0009049
Sat	-.0135268	.003763	-3.59	0.000	-.0209122	-.0061414
HS1213	.0016708	.0035681	0.47	0.640	-.0053321	.0086736
HS1314	.0221806	.0037282	5.95	0.000	.0148635	.0294976
HS1415	.025438	.0035809	7.10	0.000	.0184101	.032466
hs1516	.0164517	.0034826	4.72	0.000	.0096166	.0232869
hs1617	.0291271	.0034897	8.35	0.000	.0222781	.0359762
_cons	.0957192	.0072575	13.19	0.000	.0814754	.1099631

```
41 . save "H:\CenterPoint M Dockets\G008-M-17-533\2017 New Firm Data.dta", replace
   file H:\CenterPoint M Dockets\G008-M-17-533\2017 New Firm Data.dta saved

42 . regress smlgf17 hdd HDDs_2  Nov Dec Jan Feb Mar Sun Mon Tue Wed Thu Fri Sat HS1112 HS1213 HS1314
   >  HS1415 hs1516 hs1617
   note: Jan omitted because of collinearity
   note: Wed omitted because of collinearity
   note: HS1112 omitted because of collinearity
```

Source	SS	df	MS
Model	6.4086e+09	17	376975863
Residual	418753356	889	471038.646
Total	6.8273e+09	906	7535698.71

Number of obs	=	907
F(17, 889)	=	800.31
Prob > F	=	0.0000
R-squared	=	0.9387
Adj R-squared	=	0.9375
Root MSE	=	686.32

smlgf17	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
hdd	135.736	6.785905	20.00	0.000	122.4178	149.0543
HDDs_2	.3321659	.0809541	4.10	0.000	.1732824	.4910493
Nov	-1003.64	80.6338	-12.45	0.000	-1161.894	-845.3847
Dec	-398.2962	72.24945	-5.51	0.000	-540.0956	-256.4969
Jan	0	(omitted)				
Feb	-148.3924	73.28641	-2.02	0.043	-292.227	-4.557894
Mar	-550.8757	79.3783	-6.94	0.000	-706.6664	-395.085
Sun	-346.1268	85.40838	-4.05	0.000	-513.7524	-178.5013
Mon	121.9092	85.71869	1.42	0.155	-46.32541	290.1438
Tue	34.91184	85.317	0.41	0.682	-132.5344	202.3581
Wed	0	(omitted)				
Thu	-11.77488	85.33497	-0.14	0.890	-179.2564	155.7066
Fri	-174.0802	85.35278	-2.04	0.042	-341.5966	-6.563757
Sat	-617.9137	85.32436	-7.24	0.000	-785.3743	-450.453
HS1112	0	(omitted)				
HS1213	218.6248	80.90471	2.70	0.007	59.83832	377.4113
HS1314	526.703	84.53433	6.23	0.000	360.7929	692.6132
HS1415	316.5469	81.19435	3.90	0.000	157.192	475.9019
hs1516	231.9057	78.96688	2.94	0.003	76.92248	386.889
hs1617	412.6531	79.12744	5.22	0.000	257.3548	567.9515
_cons	2574.739	164.5601	15.65	0.000	2251.768	2897.711

```
43 . regress smlgf17 hdd HDDs_2  Nov Dec Feb Mar Sun Mon Tue Thu Fri Sat HS1213 HS1314 HS1415 hs1516
   > hs1617
```

Source	SS	df	MS
Model	6.4086e+09	17	376975863
Residual	418753356	889	471038.646
Total	6.8273e+09	906	7535698.71

Number of obs	=	907
F(17, 889)	=	800.31
Prob > F	=	0.0000
R-squared	=	0.9387
Adj R-squared	=	0.9375
Root MSE	=	686.32

smlgf17	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
hdd	135.736	6.785905	20.00	0.000	122.4178	149.0543
HDDs_2	.3321659	.0809541	4.10	0.000	.1732824	.4910493
Nov	-1003.64	80.6338	-12.45	0.000	-1161.894	-845.3847
Dec	-398.2962	72.24945	-5.51	0.000	-540.0956	-256.4969
Feb	-148.3924	73.28641	-2.02	0.043	-292.227	-4.557894
Mar	-550.8757	79.3783	-6.94	0.000	-706.6664	-395.085
Sun	-346.1268	85.40838	-4.05	0.000	-513.7524	-178.5013
Mon	121.9092	85.71869	1.42	0.155	-46.32541	290.1438
Tue	34.91184	85.317	0.41	0.682	-132.5344	202.3581
Thu	-11.77488	85.33497	-0.14	0.890	-179.2564	155.7066
Fri	-174.0802	85.35278	-2.04	0.042	-341.5966	-6.563757
Sat	-617.9137	85.32436	-7.24	0.000	-785.3743	-450.453

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HS1213	218.6248	80.90471	2.70	0.007	59.83832	377.4113
HS1314	526.703	84.53433	6.23	0.000	360.7929	692.6132
HS1415	316.5469	81.19435	3.90	0.000	157.192	475.9019
hs1516	231.9057	78.96688	2.94	0.003	76.92248	386.889
hs1617	412.6531	79.12744	5.22	0.000	257.3548	567.9515
_cons	2574.739	164.5601	15.65	0.000	2251.768	2897.711

44 .

Department Attachment 3
Docket No. G008/M-17-533
CenterPoint Demand Entitlement Analysis

Docket No.	Heating Season	Number of Firm Customers (1 A) Actual Number of Jan. Customers	(1) Projected DD Customers	(2) Change from Previous Year	(3) % Change From Previous Year	Design Day Requirement (4) Design Day (Dk)	(5) Change from Previous Year	(6) % Change From Previous Year	Total Entitlement Plus On-line Storage & Peak Shaving (7) Total Entitlement (Dk)	(8) Entitlement Change from Previous Year	(9) % Change From Previous Year	Reserve Margin (10) Corrected Reserve Margin [(7)-(4)]/(4)
17-533	2017-2018*	n/a	857,092	6,520	0.77%	1,403,000	39,000	2.86%	1,409,596	34,126	2.48%	0.47%
16-571	2016-2017	847,780	850,572	9,437	1.12%	1,364,000	11,000	0.81%	1,375,470	19,519	1.44%	0.84%
15-644	2015-2016	839,291	841,135	11,133	1.34%	1,353,000	27,000	2.04%	1,355,951	11,533	0.86%	0.22%
14-561	2014-2015	830,377	830,002	6,212	0.75%	1,326,000	2,000	0.15%	1,344,418	4,479	0.33%	1.39%
13-578	2013-2014	821,220	823,790	12,651	1.56%	1,324,000	8,000	0.61%	1,339,939	-6,842	-0.51%	1.20%
12-864	2012-2013	813,605	811,139	3,212	0.40%	1,316,000	100,000	8.22%	1,346,781	-32,900	-2.38%	2.34%
11-1078	2011-2012	807,922	807,927	3,647	0.45%	1,216,000	3,000	0.25%	1,379,681	0	0.00%	13.46%
10-1162	2010-2011	804,703	804,280	3,104	0.39%	1,213,000	2,000	0.17%	1,379,681	40,000	2.99%	13.74%
09-1260	2009-2010	801,286	801,176	4,031	0.51%	1,211,000	-24,000	-1.94%	1,339,681 1/	9,615	0.72%	**10.63%**
08-1307	2008-2009	797,228	797,145	-10,815	-1.34%	1,235,000	-11,000	-0.88%	1,330,066 1/	873	0.07%	**7.70%**
07-561	2007-2008	792,950	807,960	15,025	1.89%	1,246,000	14,000	1.14%	1,329,193 1/	26,891	2.06%	**6.68%**
06-1533	2006-2007	787,326	792,935	16,585	2.14%	1,232,000	12,000	0.98%	1,302,302	2,000	0.15%	5.71%
05-1736	2005-2006	777,424	776,350	17,129	2.26%	1,220,000	-44,000	-3.48%	1,300,302	4,500	0.35%	6.58%
	2004-2005	762,835	759,221	14,710	1.98%	1,264,000	21,000	1.69%	1,295,802	0	0.00%	2.52%
	2003-2004**	745,890	744,511	18,603	2.56%	1,243,000	29,300	2.41%	1,295,802	34,400	2.73%	4.25%
	2002-2003**	728,005	725,908	16,524	2.33%	1,213,700	30,092	2.54%	1,261,402	12,500	1.00%	3.93%
	2001-2002		709,384			1,183,608			1,248,902			5.52%
	Average Per Year:		796,502	9,232	1.19%	1,260,019	13,712	1.10%	1,331,469	10,043	0.77%	5.13%

Docket No.	Heating Season	Firm Peak Day Sendout (11) Firm Peak Day Sendout (Dk)	(12) Change from Previous Year	(13) % Change From Previous Year	Per Customer Metrics (14) Excess per Customer [(7) - (4)]/(1)	(15) Design Day per Customer (4)/(1)	(16) Entitlement per Customer (7)/(1)	(17) Peak Day Sendout per DD # Customer (11)/(1)	(18) Peak Day Sendout per Actual Customers (11)/(1 A)
17-533	2017-2018*	n/a	n/a	n/a	0.0077	1.6369	1.6446	n/a	n/a
16-571	2016-2017	978,931	(15,215)	-1.53%	0.0135	1.6036	1.6171	1.1509	1.1547
15-644	2015-2016	994,146	34,156	3.56%	0.0035	1.6085	1.6120	1.1819	1.1845
14-561	2014-2015	959,990	(126,340)	-11.63%	0.0222	1.5976	1.6198	1.1566	1.1561
13-578	2013-2014	1,086,330	125,196	13.03%	0.0193	1.6072	1.6266	1.3187	1.3228
12-864	2012-2013	961,134	130,690	15.74%	0.0379	1.6224	1.6604	1.1849	1.1813
11-1078	2011-2012	830,444	(42,328)	-4.85%	0.2026	1.5051	1.7077	1.0279	1.0279
10-1162	2010-2011	872,772	(21,153)	-2.37%	0.2072	1.5082	1.7154	1.0852	1.0846
09-1260	2009-2010	893,925	(130,839)	-12.77%	0.1606	1.5115	1.6721	1.1158	1.1156
08-1307	2008-2009	1,024,764	21,335	2.13%	0.1193	1.5493	1.6685	1.2855	1.2854
07-561	2007-2008	1,003,429	5,627	0.56%	0.1030	1.5422	1.6451	1.2419	1.2654
06-1533	2006-2007	997,802	140,866	16.44%	0.0887	1.5537	1.6424	1.2584	1.2673
05-1736	2005-2006	856,936	(87,406)	-9.26%	0.1034	1.5715	1.6749	1.1038	1.1023
	2004-2005	944,342	(69,052)	-6.81%	0.0419	1.6649	1.7068	1.2438	1.2379
	2003-2004	1,013,394	97,281	10.62%	0.0709	1.6696	1.7405	1.3612	1.3586
	2002-2003	916,113	122,670	15.46%	0.0657	1.6720	1.7377	1.2620	1.2584
	2001-2002	793,443			0.0920	1.6685	1.7605	1.1185	
	Average Per Year:	945,493	12,366	1.89%	0.0800	1.5937	1.6737	1.1936	1.2002

All the numbers reflected in the above tables are consolidated for the Company's previous Northern and Viking service areas.
* = Projected Values
** = From CenterPoint's Exh. B, page 3 in Docket No. G008/M-08-1307.
1/ Corrected total entitlement amounts for peak-shaving output. See Docket No. G008/M-10-1162.

Prepared by the Minnesota Department of Commerce, Division of Energy Resources

Department Attachment 4
Docket No. G008/M-17-533
CenterPoint Rate Impacts

Residential	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2016)	October 2017 PGA	November 2017 PGA	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.9117	$3.3747	$2.7544	$3.0030	3.14%	-11.01%	9.03%	$0.2486
Demand Cost of Gas (1)	$0.7523	$0.8070	$0.8047	$0.8022	6.63%	-0.59%	-0.31%	($0.0025)
Commodity Margin (2) (3)	$2.0648	$2.1669	$2.2201	$2.2201	7.52%	2.46%	0.00%	$0.0000
Total Cost of Gas	$5.7288	$6.3486	$5.7792	$6.0253	5.18%	-5.09%	4.26%	$0.2461
Average Annual Usage (Dk)	100	100	100	100				
Average Annual Total Cost of Gas	$572.88	$634.86	$577.92	$602.53	5.18%	-5.09%	4.26%	$24.61
Average Annual Total Demand Cost of Gas								($0.25)

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2016)	October 2017 PGA	November 2017 PGA	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.9117	$3.3747	$2.7544	$3.0030	3.14%	-11.01%	9.03%	$0.2486
Demand Cost of Gas (1)	$0.7523	$0.8070	$0.8047	$0.8022	6.63%	-0.59%	-0.31%	($0.0025)
Commodity Margin	$2.0658	$2.1679	$2.2211	$2.2211	7.52%	2.45%	0.00%	$0.0000
Total Cost of Gas	$5.7298	$6.3496	$5.7802	$6.0263	5.17%	-5.09%	4.26%	$0.2461
Average Annual Usage (Dk)	80	80	80	80				
Average Annual Total Cost of Gas	$458.38	$507.97	$462.42	$482.10	5.17%	-5.09%	4.26%	$19.69
Average Annual Total Demand Cost of Gas								($0.20)

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2016)	October 2017 PGA	November 2017 PGA	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.9117	$3.3747	$2.7544	$3.0030	3.14%	-11.01%	9.03%	$0.2486
Demand Cost of Gas (1)	$0.7523	$0.8070	$0.8047	$0.8022	6.63%	-0.59%	-0.31%	($0.0025)
Commodity Margin	$1.6740	$1.7761	$1.8293	$1.8293	9.28%	3.00%	0.00%	$0.0000
Total Cost of Gas	$5.3380	$5.9578	$5.3884	$5.6345	5.55%	-5.43%	4.57%	$0.2461
Average Annual Usage (Dk)	2,860	2,860	2,860	2,860				
Average Annual Total Cost of Gas	$15,266.68	$17,039.31	$15,410.82	$16,114.67	5.55%	-5.43%	4.57%	$703.85
Average Annual Total Demand Cost of Gas								($7.15)

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2016)	October 2017 PGA	November 2017 PGA	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.9117	$3.3747	$2.7544	$3.0030	3.14%	-11.01%	9.03%	$0.2486
Demand Cost of Gas (1)	$0.7523	$0.8070	$0.8047	$0.8022	6.63%	-0.59%	-0.31%	($0.0025)
Commodity Margin	$1.5429	$1.6450	$1.6982	$1.6982	10.07%	3.23%	0.00%	$0.0000
Total Cost of Gas	$5.2069	$5.8267	$5.2573	$5.5034	5.69%	-5.55%	4.68%	$0.2461
Average Annual Usage (Dk)	14,300	14,300	14,300	14,300				
Average Annual Total Cost of Gas	$74,458.67	$83,321.81	$75,179.39	$78,698.62	5.69%	-5.55%	4.68%	$3,519.23
Average Annual Total Demand Cost of Gas								($35.75)

Summary of Most Recent PGA

Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.2486	9.03%	-$0.0025	-0.31%	($0.25)	$24.61	4.26%
Commercial/Industrial Firm A	$0.2486	9.03%	-$0.0025	-0.31%	($0.20)	$19.69	4.26%
Commercial/Industrial Firm B	$0.2486	9.03%	-$0.0025	-0.31%	($7.15)	$703.85	4.57%
Commercial/Industrial Firm C	$0.2486	9.03%	-$0.0025	-0.31%	($35.75)	$3,519.23	4.68%

(1) Does not include Demand Smoothing.
(2) Reflects Decoupling Factor and CCRA. Does not reflect GAP, Interim or GCR Factors.
(3) Reflects decrease in CCRA of ($0.0767 per DT effective November 1, 2013 (Docket No. G008/M-13-373).

Attachment 5 – 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:

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
Public Comments

Docket No. G008/M-17-533

Dated this 2nd day of January 2018

/s/Sharon Ferguson

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