MINNESOTA DEPARTMENT OF COMMERCE

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October 2, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G008/M-14-561

Dear Dr. Haar:

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

A request by CenterPoint Energy Resources Corp., d/b/a/ CenterPoint Energy Minnesota Gas (CenterPoint, CPE, or the Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand units effective November 1, 2014. The filing was submitted on July 1, 2014. The petitioner is:

CenterPoint Energy
800 LaSalle Avenue
P.O. Box 59038
Minneapolis, MN 59459-0038

Based on its analysis, the Department recommends that the Commission approve CenterPoint's proposal, subject to supplemental filing(s) by the Company. The Department also requests that CenterPoint provide further information in its *Reply Comments*.

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

Sincerely,

/s/ ANGELA BYRNE	/s/ ADAM J. HEINEN
Financial Analyst	Rates Analyst
651-539-1820	651-539-1825

AB/AH/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. G008/M-14-561

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 1, 2014. The proposed changes do not reflect Northern Natural Gas' (Northern or NNG) 2013-2014 reallocation of units between TF-12 Base and TF-12 Variable services[3] or the final Reservation Fees cost estimate.[4]

On August 22, 2014, CenterPoint filed revisions to several exhibits in its original filing. The Company corrected its Exhibits A and B to include new storage contract costs that were inadvertently excluded from the total Annual Estimated Demand Expense.

In its *Petition*, CenterPoint requested that the Minnesota Public Utilities Commission (Commission) approve the following changes in the Company's overall level of contracted capacity.

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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.
[4] These items would require a supplemental filing(s) when the figures become known by the Company.

TABLE 1:
The Company's Proposed Total Entitlement Changes

Type of Entitlement	Proposed Changes: Increase (Decrease) (Dkt)[5]
12-month (at Lexington)	499
Winter Only	853
12-month (at Buffalo/Monticello)	1,699
5-month winter only	2,301
Propane Peak Shaving	(1,033)

CPE described the only factor contributing to the need for changing demand is an increase in pipeline entitlement due to growth in specific service areas.[6] The effect of this change results in an overall increase 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 margin; and
- the PGA cost recovery proposal.

A. PROPOSED CHANGES

1. Changes to the Entitlement Level

As indicated below and in DOC Attachment 1, the Company proposed to increase its total entitlement level over the prior year by 4,319 Dkt as follows:

Table 2

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
1,340,099	1,344,418	4,319	0.32%

CenterPoint discussed that growth in the Lexington and Buffalo/Monticello areas resulted in an overall increase in its total entitlement level. Specifically, CPE plans to add 499 Dekatherms (Dkt) of 12-month and 853 Dkt of Winter only at Lexington, and 1,699 Dkt 12-month and 2,301 5-month Winter at Buffalo/Monticello.

[5] Dekatherms (Dkt or DT).
[6] *Petition*, Page 1.

Based on its analysis, the Department concludes that CenterPoint's proposed level of demand entitlement is reasonable. The Department recommends approval subject to the supplemental filing(s) that will be submitted by the Company once the reallocation of units between TF-12 Base and TF-12 Variable services and the final Reservation Fees cost estimate are known.

2. Changes to Non-Capacity Items

As was done in the 2011 through 2013 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.

CenterPoint also had several changes to its various storage contracts. The first change extended its Tenaska storage at a lower rate. The Company stated that this service has been beneficial by providing needed flexibility and capturing the favorable difference in summer prices versus winter prices that typically occurs.

Second, the Company added an additional 5 Billion Cubic Feet of storage capacity with a maximum daily withdrawal of 50,000 Dkt with BP Storage. CenterPoint stated that this additional storage provides both flexibility to handle load swings and price protection from spikes in daily priced gas like those faced during the 2013-2014 winter.

Third, CenterPoint added an additional 500,000 Cubic Feet of FDD Storage, with a maximum daily withdrawal of 8,647 Dkt. The Company stated that having FDD storage capacity allows it to make real time adjustments to daily supplies (one hour before the start of the gas day), which is not provided by any other service. CenterPoint also stated that this service provides for resolution of monthly imbalance volumes.

Finally, CenterPoint proposed to allocate the two new storage contracts' fixed costs by allocating 75 percent to demand costs and 25 percent to commodity costs. The Company stated that this allocation is like the allocation used for reservations fees as detailed in Docket No. G008/M-11-1078.[7]

It is unclear to the Department why the allocation of the two new storage contracts would be similar to reservation fees, rather than to other storage contracts currently held by the Company. In Docket No. G008/M-07-561, the Commission ordered CenterPoint to allocate costs associated with NGPL Storage 65.69 percent to firm and small volume dual fuel customers based on sales, and include the remaining 34.31 percent in commodity costs allocated to all sales customers based on sales volumes.[8] Additionally, costs associated with CenterPoint's Tenaska storage contract are allocated 25 percent to demand and 75 percent to commodity.[9] The Department requests that CenterPoint provide a detailed discussion in

[7] *Petition*, Page 1.
[8] Page 4 of the Commission's *Order Approving Changes in Demand Entitlements and Setting Further Requirements* issued February 28, 2012 in Docket Nos. G008/M-07-561 and G008/M-11-1078.
[9] Docket No. G008/M-11-1078.

its *Reply Comments* regarding its proposal to allocate its two new storage contracts 75 percent to demand and 25 percent to commodity, as it does with reservation fees.

The Department will provide its recommendation on non-capacity items after reviewing the additional information provided by CenterPoint.

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's 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 2008 to March 2014. CPE used HDDs and the squared value of HDDs (HDD^2) to estimate daily firm use per customer (UPC). 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 analysis, and concludes that the signs on HDD and HDD^2 are both positive and the scale of the coefficients appear to be reasonable.

As noted earlier, the Company's analysis is based on daily throughput (use per customer) and weather data over the period from November 2008 to March 2014. CenterPoint's analysis results in a design-day estimate of 1,229,000 Dkt/day; however, as explained in 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 1,290,000 Dkt/day, which is 2,000 Dkt/day greater than the design-day estimate in last year's demand entitlement filing. 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.

Since CenterPoint's design-day method is relatively new (this marks the third filing that it has been used), the Department does not oppose the Company's decision to use the upper bound of its regression analysis. This approach would place a greater emphasis on reliability, all else being equal, and provide a buffer for firm ratepayers until more actual experience with this design day method exists. It is important to note that last heating season (2013-2014 heating season) was marked by extreme weather conditions, including near design-day conditions. CenterPoint's projections in the last demand entitlement were sufficient to ensure firm reliability; however, the peak sendout during the last heating season occurred on a day warmer than 90 HDD. The Department discusses this in greater detail in the following section of these *Comments*.

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

b. Department's Alternative Design-Day Analysis

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 (DOC Attachment 4). 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. This approach is conservative and biases the calculation in the favor of system reliability. Using this approach, the additional regression factors decrease the projected design day by a small amount from CenterPoint's 1,229,000 Dkt/day figure to approximately 1,223,265 Dkt/day as calculated using the Department's model, but the results are within the confidence interval from the Company's design-day analysis.

For comparative purposes, the Department also calculated its design-day result based on the upper bound of its regression result. Using the upper bound, the Department's estimated design day, approximately 1,329,741 Dkt/day, is higher than CenterPoint's proposed total entitlement level of 1,290,000 Dkt/day. A strict interpretation of this result suggests that, based on the Department's analysis, the Company may not have sufficient capacity to ensure firm service on a peak day (90 HDD). However, the Department believes that the upper bound result is highly unlikely and thus does not suggest that CPE has insufficient firm capacity. In addition, when the Department's upper bound estimate is compared to CPE's upper bound design-day estimate, inclusive of physical reserves (1,344,418 Dkt/day), the figures are roughly equal which means firm reliability should be ensured. The Department's upper bound result might happen only if peak usage were at the top of reasonable peak usage expectations on a peak day (90 HDD) that occurs on a Tuesday, in January, and during a heating season with usage characteristics similar to the 2013-2014 heating season. The Department has not determined the statistical probability, but it is clear that the odds of this happening are remote. In addition, it is important to consider that all regression results are subject to error. As such, the Department believes that CPE likely has sufficient capacity to serve needs on an all-time peak day.

Given the Department's results and their similarity to CenterPoint's proposed design day, the Department concludes that the Company's design day is reasonable. Thus, the

Department recommends that the Commission accept the design-day level proposed by CPE.

As noted earlier in these *Comments*, the last heating season was marked by some of the coldest weather on the CenterPoint system in the last 20 years. In fact, there were three days where firm throughput was greater than 1,000,000 Dkt over the course of a single day. The Department reviewed the daily data provided by the Company (Exhibit B, Pages 5 through 18 of CenterPoint's *Petition*) and notes that the greatest throughput during the past heating season, 1,086,330 Dkt, occurred on a day with a HDD value of 79; as such, if a Commission peak day (90 HDD) had occurred total throughput would have been even higher. Since the peak throughput from last heating season occurred on a day relatively close to a Commission peak day, it is possible to estimate the relative accuracy of the Company's peak-day analysis.

Using the regression coefficients from the Company's design-day model (Exhibit B, Page 1 of the Company's *Petition*), the Department determined that firm throughput would have been 1,203,690 Dkt on last heating season's peak day if the average temperature was 90 HDD. This result is 25,310 Dkt, or 2.1 percent, lower than the regression estimated design-day figure of 1,229,000 Dkt calculated in last year's demand entitlement filing. In addition, this result is 84,310 Dkt, or 7.00 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 shows that CenterPoint likely had sufficient entitlements to serve firm customers on a Commission peak day; especially considering that the total entitlement level (which is inclusive of the reserve margin and physical reserves) was 52,099 Dkt greater than the upper-bound result.

Further, the results from the 2013-2014 peak day suggest that use of the upper-bound from the design-day regression model to estimate total entitlement levels, which was used by CenterPoint in the current demand entitlement filing as well, may not be necessary on a going forward basis. As noted above, the Department concludes that the Company's proposed total entitlement level is reasonable because a bias towards ensuring reliability is appropriate given the relatively short time the underlying methodology has been in use; however, the Department requests that CenterPoint use its regression point estimate, and not the upper-bound of its analysis, in future demand entitlement filings. Based on the Department's review of historical usage from the 2013-2014 heating season, use of the regression model point estimate will ensure firm reliability and potentially reduce demand costs.

4. *Reserve Margin*

As shown below and in DOC Attachment 2, CPE's proposed reserve margin is 1.40 percent:

Table 3

Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year[10]
1,344,418	1,326,000	(18,418)	1.40%	0.20%

Despite an increase in estimated design day, CenterPoint's reserve margin still increased slightly due to the increase in the entitlement level.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amount listed in DOC Attachment 1 represents the demand entitlements for which the Company's firm customers will be paying November 1, 2014 (excluding costs related to the reallocation of units between TF-12 Base and TF- Variable services and the final Reservation Fees cost estimate at this time). In its *Petition*, CenterPoint compared its July 2014 PGA rates to its proposed November 2014 PGA which resulted in an increase of demand costs by $0.0108 per Dkt for the Residential class. As shown in DOC Attachment 3, 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 increase of $10.80, or approximately 16.30 percent, for the average Residential customer consuming 100 Dkt annually;
- Annual demand cost increase of $8.64, or approximately 16.30 percent, for the average Commercial/Industrial Firm - A customer consuming 80 Dkt annually;
- Annual demand cost increase of $308.88, or approximately 16.30 percent, for the average Commercial/Industrial Firm - B customer consuming 2,860 Dkt annually; and
- Annual demand cost increase of $1,544.40, or approximately 16.30 percent, for the average Commercial/Industrial Firm - C customer consuming 14,300 Dkt annually.

The increase in demand costs is partially driven by CenterPoint's new storage contracts, as discussed above. Since the Department has requested additional information regarding the Company's proposed allocation of these new contracts, the Department will withhold its recommendation on approval of proposed demand costs pending review of CenterPoint's *Reply Comments*.

[10] As shown on DOC Attachment 2, the Company's average reserve margin since 2001-2002 is 6.12 percent.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission:

- approve CenterPoint's proposed level of demand entitlement subject to supplemental filing(s) by the Company related to the reallocation of units between TF-12 Base and TF-12 Variable services and the final Reservation Fees cost estimate; and
- accept the design-day level proposed by CPE.

The Department requests that CenterPoint use its regression point estimate, and not the upper-bound of its design-day analysis, in future demand entitlement filings.

The Department also requests that, in its *Reply Comments*, CenterPoint provide a detailed discussion regarding its proposal to allocate its two new storage contracts 75 percent to demand and 25 percent to commodity, as it does with reservation fees.

Finally, the Department will provide a final set of recommendations to the Commission after it reviews CenterPoint's *Reply Comments*.

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Heating Season Services	{1} CenterPoint Energy 12-864 (Jan 2013) Quantity (Dkt)	{2} CenterPoint Energy 13-578 (July 2013) Quantity (Dkt)	{3} CenterPoint Energy 13-578 (Jan 2014) Quantity (Dkt)	{4} CenterPoint Energy 14-561 (July 2014) Quantity (Dkt)	{5} TOTAL Change (Jan. 2014 - Jul. 2014) {4}-{3}
	[TRADE SECRET DATA BEGINS				
NNG TF-12 Base Winter					
NNG TF-12 Base Summer					
NNG TF-12 Variable Winter					
NNG TF-12 Variable Summer					
NNG TF-12 Growth Winter					
NNG TF-12 Growth Summer					
NNG TF-5					
NNG TF-5 Growth					
TFX-Winter 5 mo. (non-discounted)					
TFX-Summer 7 mo. (non-discounted)					
TFX-A1-winter					
TFX-A1-summer					
TFX-A1-winter					
TFX-A1-summer					
TFX-B1-winter					
TFX-B1-summer					
TFX-B2-winter					
TFX-B2-summer					
TFX-C1-winter					
TFX-C1-summer					
TFX-C2-winter					
TFX-C2-summer					
					TRADE SECRET DATA ENDS]
Total NNG Demand Winter	978,872	981,497	981,657	987,009	5,352
Total NNG Demand Summer	551,673	553,413	553,531	555,729	2,198
	[TRADE SECRET DATA BEGINS				
Reservation - Waterville (151 days)					
Waterville - SBA					
SMS					
Viking					
FT-A - 12 month					
FT-A - 5 month (5,000 5 mo.)					
					TRADE SECRET DATA ENDS]
Total Viking Demand	56,809	56,809	56,809	56,809	0
Supply Demand					
	[TRADE SECRET DATA BEGINS				
Seasonal Reservation					
Storage NGPL					
Storage Tennaska					
					TRADE SECRET DATA ENDS]
NOTE: Reflects total volumes contracted and does not reflect any cost allocation.					
Released Capacity	(1,500)	0	0	0	0
Underground Storage	50,000	50,000	50,000	50,000	0
LNG Peak Shaving	72,000	72,000	72,000	72,000	0
Propane Peak Shaving	188,800	179,633	179,633	178,600	(1,033)
Total Propane	310,800	301,633	301,633	300,600	(1,033)
Total Capacity	1,344,981	1,339,939	1,340,099	1,344,418	4,319
Total Peak-Shaving Capacity/On-line Storage	310,800	301,633	301,633	300,600	(1,033)
Total Annual Transportation	608,482	610,222	610,340	612,538	2,198
Total Seasonal Transportation	1,034,181	1,038,306	1,038,466	1,043,818	5,352
Peak Shaving as % of Total Capacity	23.1%	22.5%	22.5%	22.4%	-0.1%
Annual Transportation as % of Total Capacity	45.2%	45.5%	45.5%	45.6%	0.0%
Seasonal Transportation as % of Total Capacity	76.9%	77.5%	77.5%	77.6%	0.1%
Annual and Seasonal Transportation as % of Total Transportation	63.0%	63.0%	63.0%	63.0%	0.0%

Docket No. G008/M-14-561
DOC Attachment 2
Page 1 of 1

CenterPoint Energy

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 + 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)	(10.5) As Reported Reserve Margin
14-561	2014-2015*	n/a	830,002	6,212	0.75%	1,326,000	2,000	0.15%	1,344,418		4,479	0.33%	1.39%	1.40%
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%	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%	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%	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%	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%**	9.78%
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%**	6.87%
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%**	5.63%
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%	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%	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%	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%	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%	3.93%
	2001-2002		709,384			1,183,608			1,248,902				5.52%	5.52%
	Average Per Year:		785,123	9,278	1.22%	1,245,951	10,953	0.91%	1,320,997		7,347	0.58%	6.12%	

Heating Season	Firm Peak Day Sendout (11) Firm Peak Day Sendout (Dk)	(12) Change from Previous Year	(13) % Change From Previous Year	Amounts per Customer (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)
2014-2015*	n/a	n/a	n/a	0.0222	1.5976	1.6198	n/a	n/a
2013-2014	1,086,330	125,196	13.03%	0.0193	1.6072	1.6266	1.3187	1.3228
2012-2013	961,134	130,690	15.74%	0.0379	1.6224	1.6604	1.1849	1.1813
2011-2012	830,444	(42,328)	-4.85%	0.2026	1.5051	1.7077	1.0279	1.0279
2010-2011	872,772	(21,153)	-2.37%	0.2072	1.5082	1.7154	1.0852	1.0846
2009-2010	893,925	(130,839)	-12.77%	0.1606	1.5115	1.6721	1.1158	1.1156
2008-2009	1,024,764	21,335	2.13%	0.1193	1.5493	1.6685	1.2855	1.2854
2007-2008	1,003,429	5,627	0.56%	0.1030	1.5422	1.6451	1.2419	1.2654
2006-2007	997,802	140,866	16.44%	0.0887	1.5537	1.6424	1.2584	1.2673
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:	938,064	24,407	3.16%	0.0953	1.5888	1.6842	1.2006	1.2090

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

Residential	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-13-578) (Jan 2014)	June 2014 PGA before proposed demand entitlement change	Nov. 2014 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$4.7594	$4.7509	$4.7509	-21.72%	-0.18%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7280	$0.6624	**$0.7704**	**-8.30%**	**5.82%**	**16.30%**	**$0.1080**
Commodity Margin (2) (3)	$1.6637	$1.7308	$1.7595	$1.7595	5.76%	1.66%	0.00%	$0.0000
Total Cost of Gas	$8.5728	$7.2182	$7.1728	$7.2808	-15.07%	0.87%	1.51%	$0.1080
Average Annual Usage (Dk)	100	100	100	100				
Average Annual Total Cost of Gas	$857.28	$721.82	$717.28	$728.08	-15.07%	0.87%	1.51%	$10.80
Average Annual Total Demand Cost of Gas								**$10.80**

Commercial/Industrial Firm - A	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-13-578) (Jan 2014)	June 2014 PGA before proposed demand entitlement change	Nov. 2014 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$4.7594	$4.7509	$4.7509	-21.72%	-0.18%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7280	$0.6624	**$0.7704**	**-8.30%**	**5.82%**	**16.30%**	**$0.1080**
Commodity Margin	$1.4680	$1.6159	$1.3197	$1.3197	-10.10%	-18.33%	0.00%	$0.0000
Total Cost of Gas	$8.3771	$7.1033	$6.7330	$6.8410	-18.34%	-3.69%	1.60%	$0.1080
Average Annual Usage (Dk)	80	80	80	80				
Average Annual Total Cost of Gas	$670.17	$568.26	$538.64	$547.28	-18.34%	-3.69%	1.60%	$8.64
Average Annual Total Demand Cost of Gas								**$8.64**

Commercial/Industrial Firm - B	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-13-578) (Jan 2014)	June 2014 PGA before proposed demand entitlement change	Nov. 2014 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$4.7594	$4.7509	$4.7509	-21.72%	-0.18%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7280	$0.6624	**$0.7704**	**-8.30%**	**5.82%**	**16.30%**	**$0.1080**
Commodity Margin	$1.4422	$1.4094	$1.3689	$1.3689	-5.08%	-2.87%	0.00%	$0.0000
Total Cost of Gas	$8.3513	$6.8968	$6.7822	$6.8902	-17.50%	-0.10%	1.59%	$0.1080
Average Annual Usage (Dk)	2,860	2,860	2,860	2,860				
Average Annual Total Cost of Gas	$23,884.72	$19,724.85	$19,397.09	$19,705.97	-17.50%	-0.10%	1.59%	$308.88
Average Annual Total Demand Cost of Gas								**$308.88**

Commercial/Industrial Firm - C	Last Rate Case (G008/GR-08-1075)	Last Demand Change (G008/M-13-578) (Jan 2014)	June 2014 PGA before proposed demand entitlement change	Nov. 2014 PGA with Proposed Demand Entitlement Change	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)	$6.0690	$4.7594	$4.7509	$4.7509	-21.72%	-0.18%	0.00%	$0.0000
Demand Cost of Gas (1)	$0.8401	$0.7280	$0.6624	**$0.7704**	**-8.30%**	**5.82%**	**16.30%**	**$0.1080**
Commodity Margin	$1.3362	$1.2698	$1.3453	$1.3453	0.68%	5.95%	0.00%	$0.0000
Total Cost of Gas	$8.2453	$6.7572	$6.7586	$6.8666	-16.72%	1.62%	1.60%	$0.1080
Average Annual Usage (Dk)	14,300	14,300	14,300	14,300				
Average Annual Total Cost of Gas	$117,907.79	$96,627.96	$96,647.98	$98,192.38	-16.72%	1.62%	1.60%	$1,544.40
Average Annual Total Demand Cost of Gas								**$1,544.40**

Summary Change from 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	$0.0000	0.00%	$0.1080	16.30%	$10.80	$10.80	1.51%
Commercial/Industrial Firm A	$0.0000	0.00%	$0.1080	16.30%	$8.64	$8.64	1.60%
Commercial/Industrial Firm B	$0.0000	0.00%	$0.1080	16.30%	$308.88	$308.88	1.59%
Commercial/Industrial Firm C	$0.0000	0.00%	$0.1080	16.30%	$1,544.40	$1,544.40	1.60%

(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).

Source	SS	df	MS		
Model	47.64063	17	2.80239017	Number of obs	907
Residual	0.844356	889	0.000949782	Prob > F	0
				R-squared	0.9826
				Adj R-squared	0.9823
Total	48.48499	906	0.05351544	Root MSE	0.03082

upc	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
hdd	0.011943	0.0003 079	38.79	0	0.0113386	0.0125472
HDD_2	3.15E-05	3.60e -06	8.76	0	0.0000245	0.0000386
Nov	-0.05602	0.0039 082	-14.33	0	-0.063692	-0.0483515
Dec	-0.02286	0.003 249	-7.04	0	-0.02924	-0.0164867
Jan	(omitted)					
Feb	-0.02042	0.0033 457	-6.10	0	-0.0269829	-0.0138501
Mar	-0.03914	0.003 752	-10.43	0	-0.0465	-0.0317725
Sun	0.005514	0.0038 305	1.44	0.15	-0.0020038	0.0130318
Mon	0.005676	0.0038 314	1.48	0.139	-0.0018441	0.0131953
Tue	0.007227	0.0038 308	1.89	0.06	-0.0002912	0.0147459
Wed	(omitted)					
Thu	-0.00452	0.0038 412	-1.18	0.24	-0.0120585	0.0030193
Fri	-0.00597	0.0038 423	-1.55	0.12	-0.0135134	0.0015687
Sat	-0.01224	0.0038 312	-3.19	0.001	-0.0197586	-0.0047199
HS0809	-0.01052	0.0035 729	-2.94	0.003	-0.0175274	-0.0035027
HS0910	-0.03095	0.003 653	-8.47	0	-0.0381208	-0.0237819
HS1011	-0.02598	0.0035 998	-7.22	0	-0.0330448	-0.0189145
HS1112	-0.02951	0.0038 417	-7.68	0	-0.037047	-0.0219674
HS1213	-0.02364	0.003 646	-6.48	0	-0.0307949	-0.0164832
hs1314	(omitted)					
_cons	0.143799	0.0083 496	17.22	0	0.1274117	0.1601862

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Comments

Docket No. **G008/M-14-561**

Dated this 2nd day of October 2014

/s/Sharon Ferguson

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