MINNESOTA DEPARTMENT OF COMMERCE

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November 29, 2016

Daniel P. Wolf
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-16-571

Dear Mr. Wolf:

Attached are the *Comments* of the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) 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 or PUC) of a change in demand units effective November 1, 2016.

The filing was submitted on July 1, 2016. A supplemental filing was submitted on November 1, 2016. The petitioner is:

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

Based on its analysis, the Department recommends that the Minnesota Public Utilities Commission approve CenterPoint's proposal.

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

Sincerely,

/s/ MICHAEL RYAN
Rates Analyst

/s/ ADAM J. HEINEN
Rates Analyst

MR/AJH/lt
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. G008/M-16-571

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, 2016. 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. Also, the proposed changes from the *Petition* did not reflect Northern Natural Gas' (Northern or NNG) 2016-2017 reallocation of units between TF-12 Base and TF-12 Variable services.[3]

On November 1, 2016, 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 no changes in the Company's overall level of contracted capacity. But in the updated *Supplemental Filing*, CenterPoint added 4,319 Dkt[4] per day of winter entitlement and 799 Dkt per day of summer entitlement on Northern Natural Gas (NNG). The breakout of the entitlement is listed below in Table 1.

[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] Dekatherms (Dkt or DT).

Table 1 – Demand Entitlement Changes

Pipeline Receipt Point	Pipeline Delivery Point	Proposed Changes: Increase (Decrease) (Dkt)	
		5-month (Winter)	7-month (Summer)
NNG - Marshall	Willmar	1,609	650
NNG – Marshall	Litchfield	24	10
NNG - Carlton	Lexington	1,750	0
NNG – Carlton	Elk River	634	0
NNG – Pierz	Avon – St. John	302	139
TOTAL		**4,319**	**799**

CenterPoint stated that entitlements were made available on the capacity market or through alternative delivery options. The Company monitors NNG for potential capacity and purchases for areas of CenterPoint's distribution system that have little to no excess capacity. The capacity is meant to better support need in constrained areas.[5]

In addition to the increased demand entitlement, the Company reported in the *Petition* that the propane peaking capacity would be increasing by 9,200 Dth per day for the upcoming winter due to a new plant coming into service. The *Supplemental Filing* confirmed that the plant would be coming into service.

CenterPoint also 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 in the process of comparing storage bids because the existing storage contracts with NNG and BP Canada expired. Ultimately the Company consolidated storage contracts by contracting for a larger volume with Tenaska and not renewing storage contracts with BP Canada or NNG. The net change in storage compared to the prior year was an increase of 1,328 Dth.

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

The *Supplemental Filing* results 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

[5] *Supplemental Filing*, Page 2.

- the PGA cost recovery proposals.

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 from the prior year by 13,519 Dkt as follows:

Table 2 – CenterPoint's Total Entitlement Levels

Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	% Change From Previous Year
1,355,951	1,369,470	13,519	0.00997%

CenterPoint's increase to entitlement was largely attributed to an additional propane peaking plant coming into service for the 2016-2017 heating season. The Company stated that the plant will add an additional 9,200 Dkt of peaking capacity. In addition to the peaking plant, the Company added 4,319 Dkt of additional capacity on NNG for the upcoming winter to better support expected load. The capacity additions are small when compared to the overall amount of winter entitlement that the Company purchases on NNG - less than one half of one percent.

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's storage contracts with BP Canada and NNG expired. Due to the expiration of the contracts, the Company conducted a bidding process to gauge the market for storage capability. Tenaska's bid was the most competitive as indicated by the Company.[6] Table 3 below illustrates the change in volume due to the changes in contracted storage.

[6] *Petition*, page 1.

Table 3 – CenterPoint Storage

Storage Contract	2015-16 Heating Season (Dkt)	2016-17 Heating Season (Dkt)	Year-Over-Year Change (Dkt)	Year-Over-Year Change (%)
Storage NGPL	210,986	210,986	-	0.00%
Storage Tenaska	60,000	120,000[7]	**60,000**	100.00%
Storage BP Canada	50,000	-	**(50,000)**	-100.00%
Storage NNG FDD	8,672	-	**(8,672)**	-100.00%
Total	**329,658**	**330,986**	**1,328**	**0.40%**

Overall, total storage capacity increased by 1,328 Dkt as a result of CenterPoint consolidating its storage contracts from four parties down to two. Storage does not directly add to the amount of capacity available for CenterPoint to transport natural gas on a daily basis, but is used to mitigate commodity price volatility and to provide a physical backup closer to the market in case of constraints or ongoing delivery issues.

In email follow up, the Department requested additional information on the Seasonal Reservation volume that increased from 245,000 Dkt to 300,000 Dkt for the upcoming winter. [8] The Company confirmed that the Seasonal Reservation volume increased year-over-year, but cost of the reservation fees was lower due to market conditions. Overall, the increase in Seasonal Reservation was driven by CenterPoint's aggregate gas supply plan to incorporate more swing supply vs. baseload gas to add flexibility. With swing supply, the Company pays a reservation fee, but does not commit to buying the full amount. The Company elects the amount of natural gas required each month and pays a daily index price. The Department appreciates the Company providing additional information and confirms that the additional swing supply is reasonable as part of the gas supply plan.

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 Energy in this filing is similar to what was used by the Company in recent demand entitlement filings. CenterPoint Energy'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 2010 to March 2016. CPE used heating degree days (HDDs) and the

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[7] In the *Supplemental Filing* Exhibit B, pg. 2, the Company lists the Tenaska Storage for the 2016-17 heating season as 95,000 Dkt. Upon follow-up email discussion with CenterPoint, the total volume contracted is 120,000 Dkt inclusive of baseload and swing volume. The *Supplemental Filing* only included the swing portion of 95,000 Dkt.

[8] *Supplemental Filing*, Exhibit B, pg. 2.

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 Energy's design-day regression analysis, 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 earlier, the Company's analysis is based on daily throughput (use per customer) and weather data over the period from November 2010 to March 2016. CenterPoint Energy's analysis results in a design-day estimate of 1,265,000 Dkt/day; 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 1,328,000 Dkt/day, which is 11,000 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.

The peak-day estimation 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 Energy'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 non-weather 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 Energy'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, should the additional factors be 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 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. This approach is conservative and should bias 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 Energy's 1,265,000 Dkt/day figure to approximately 1,255,788 Dkt/day, 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 1,321,220 Dkt/day, is slightly less than CenterPoint Energy's proposed total entitlement level of 1,328,000 Dkt/day. This result suggests that the Company's proposed entitlement level, which does not reflect additional physical capacity that is available on a peak day, is sufficient to ensure firm reliability on a Commission peak day.

Given the Department's results and the similarity to CenterPoint Energy's proposed design day level, the Department concludes that the Company's design day estimation is reasonable; however, the process remains relatively new and will continue to be reviewed over time. Thus, the Department recommends that the Commission accept the design-day level proposed by CPE.

c. Department's After-the-Fact Design-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 1,185,199 Dkt on the last heating season's peak day if the average temperature was 90 HDD. This level of firm throughput is 68,801 Dkt, or 5.8 percent, lower than the Company's regression-estimated design-day figure of 1,254,000 Dkt calculated in last year's demand entitlement filing. In addition, this result is 131,801 Dkt, or 11.12 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 use of CenterPoint's design-day model reasonably ensured that the Company likely had sufficient entitlements to serve firm customers had there been a Commission peak day during the last heating season.

The Department also conducted an after-the-fact analysis similar to the analysis used by the Company in its initial filing but using the alternative calculation discussed above that considered non-weather factors. The predicted sales for the 2015-2016 heating season peak day are similar to CenterPoint's actual sales (991,205 Dkt estimated sales compared to actual sales of 994,146 Dkt) and also suggest that the Department's design-day model may have a slight 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 than the 90 HDD planning objective. As such, it is unclear if the model may also have a bias toward under-estimation of sales on an all-time peak day.

The Department's review suggests that the Company's design-day analysis is reasonable. The Department had expressed concern in previous demand entitlement filings that CenterPoint's use of the upper-bound of its regression model may be inappropriate because it would result in the procurement of too many entitlements. However, as noted by the Department's after-the-fact analysis, the Department concludes that, since the Company's estimate is close to the Department's and the Department's method may have a slight bias toward under-estimating sales, CenterPoint's use of the upper-bound figure is not unreasonable at this time since it is unlikely to be overly biased toward firm reliability. The Department will continue to monitor this method in future demand entitlement filings.

4. *Reserve Margin*

As shown below and in DOC Attachment 3, CPE's proposed reserve margin is 0.40 percent:

Table 4 – CenterPoint Reserve Margin

Total Entitlement (Dkt)	Design-day Estimate (Dkt)[9]	Difference (Dkt)	Reserve Margin (%)	Percentage Point Change From Prior Year
1,369,470	1,364,000	5,470	0.40%	0.18%

Both the total entitlement and design-day estimate increased when compared to the prior year. The entitlement increased 2,519 Dkt more than the design-day resulting in a 0.18 percentage point increase in reserve margin when compared to the prior year. Although there is an increase in reserve margin the Department notes that a 0.40% 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, which is higher than the point estimate design-day used by the Department. 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 in Section II.3. 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.

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, 2016. In its *Petition*, CenterPoint compared its October 2016 PGA rates to its proposed November 2016 PGA which resulted in a decrease of demand costs by $0.0203 per Dkt for the Residential class. As shown in DOC 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 $2.03, or approximately 2.46 percent, for the average Residential customer consuming 100 Dkt annually;
- Annual demand cost decrease of $1.62, or approximately 2.46 percent, for the average Commercial/Industrial Firm - A customer consuming 80 Dkt annually;
- Annual demand cost decrease of $58.06, or approximately 2.46 percent, for the average Commercial/Industrial Firm - B customer consuming 2,860 Dkt annually; and

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[9] Design-Day Estimate includes CenterPoint's Calculated Design-Day of 1,328,000 Dkt and the Physical Reserve of 36,000 as shown in *Petition* at pg. 2. If the Physical Reserve is removed, the Company's Reserve Margin is approximately 3.12%.

- Annual demand cost decrease of $290.29, or approximately 2.46 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 sales volume estimates made in the most recent rate case, Docket No. G008/15-424. Without the adjustment to sales volume, demand cost on a per-unit basis would have increased because the overall demand costs increased by $7.7 million.

Also of note, the Company inadvertently did not include the Waterville Storage costs in the November 2016 PGA, but included the costs in the *Supplemental Filing*.[10] The result was a reduced annual demand cost on the November 2016 PGA of $551,000 or $.00051/Dth. The costs associated with Waterville will be collected in the December 2016 PGA.

Based on its analysis, the Department recommends that the Commission approve the proposed demand costs with an effective date of November 1, 2016.

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, 2016; and
- accept the design-day level proposed by CPE.

/lt

[10] *Supplemental Filing*, pg. 2.

Department Attachment 1
Docket No. G008/M-16-571
CenterPoint Demand Entitlement Historical and Current Proposal

Heating Season Services	{1} CenterPoint Energy 14-561 (July 2014) Quantity (Dkt)	{2} CenterPoint Energy 14-561 (Jan 2015) Quantity (Dkt)	{3} CenterPoint Energy 15-644 (July 2015) Quantity (Dkt)	{4} CenterPoint Energy 15-644 (Dec 2015) Quantity (Dkt)	{5} CenterPoint Energy 16-571 (July 2016) Quantity (Dkt)	{6} CenterPoint Energy 16-571 (Nov 2016) Quantity (Dkt)	{7} TOTAL Change (Dec. 2015 - Nov. 2016)
[TRADE SECRET DATA BEGINS							{6}-{4}
NNG TF-12 Base Winter							
NNG TF-12 Base Summer							
NNG TF-12 Base Winter-Disc							
NNG TF-12 Base Summer-Disc							
NNG TF-12 Variable Winter							
NNG TF-12 Variable Summer							
NNG TF-12 Variable Winter-Disc							
NNG TF-12 Variable Summer-Disc							
NNG TF-12 Base Winter							
NNG TF-12 Base Summer							
NNG TF-12 Growth Winter							
NNG TF-12 Growth Summer							
NNG TF-5							
NNG TF-5							
NNG TF-5 Growth							
NNG TF-5							
NNG TF-5 Growth							
TFX-Winter 5 mo. (non-discounted)							
TFX-Winter 4 mo. (non-discounted)							
TFX-Summer 7 mo. (non-discounted)							
TFX-Summer 7 mo. (non-discounted)							
TFX-A1-winter							
TFX-A1-summer							
TFX-A2-winter							
TFX-A2-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]
NNG Demand Winter	987,009	987,009	1,018,671	1,021,056	1,021,056	1,025,375	4,319
NNG entitlements sources from Viking			(24,914)	(24,914)	(24,914)	(24,914)	0
Total NNG Demand Winter			993,757	996,142	996,142	1,000,461	4,319
Total NNG Demand Summer	555,729	555,729	574,472	574,667	574,667	575,466	799
[TRADE SECRET DATA BEGINS							
Reservation - Waterville (151 days)							
Waterville - SBA							
SMS							
Viking							
FT-A - 12 month							
FT-A - 12 month							
FT-A - 3 month							
							TRADE SECRET DATA ENDS]
Total Viking Demand	56,809	56,809	56,809	66,809	66,809	66,809	0
Trailblazer (FTS Backhaul)		50,000	100,000	100,000	100,000	100,000	0
Supply Demand							
[TRADE SECRET DATA BEGINS							
Seasonal Reservation							
Storage NGPL							
Storage Tenaska							
Storage BP Canada							
Storage Northern Natural FDD							
							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
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	178,600	178,600	171,000	171,000	180,200	180,200	9,200
Total Peaking	300,600	300,600	293,000	293,000	302,200	302,200	9,200
Total Capacity	1,344,418	1,344,418	1,343,566	1,355,951	1,365,151	1,369,470	13,519
Total Peak-Shaving Capacity/On-line Storage	300,600	300,600	293,000	293,000	302,200	302,200	9,200
Total Annual Transportation	612,538	612,538	631,281	631,476	631,476	632,275	799
Total Seasonal Transportation	1,043,818	1,043,818	1,050,566	1,063,146	1,065,146	1,067,270	4,124
Peak Shaving as % of Total Capacity	22.4%	22.4%	21.8%	21.6%	22.1%	22.1%	0.5%
Annual Transportation as % of Total Capacity	45.6%	45.6%	47.0%	46.6%	46.3%	46.2%	-0.4%
Seasonal Transportation as % of Total Capacity	77.6%	77.6%	78.2%	78.4%	78.0%	77.9%	-0.5%
Annual and Seasonal Transportation as % of Total Transportation	63.0%	63.0%	62.5%	62.7%	62.8%	62.8%	0.1%

Department Attachment 2
Docket No. G.008/M-16-571
Design-Day Output

```
. regress upc hdd HDDs_2 Nov Dec Feb Mar Sun Tue Wed Thu Fri Sat HS1011 HS12
> 13 HS1314 HS1415 hs1516
     Source |       SS       df       MS                  Number of obs =     9
-------------+------------------------------               F( 17,   889) = 2919.
      Model |  47.4044276    17  2.78849574               Prob > F      =  0.00
   Residual |   .84924945   889  .000955286               R-squared     =  0.98
-------------+------------------------------               Adj R-squared =  0.98
      Total |  48.2536771   906  .053260129               Root MSE      =  .030
```

upc	Coef.	Std. Err.	t	P>t	[95% Conf.	Interva
hdd	.0125508	.0003157	39.76	0.000	.0119312	.01317
HDDs_2	.0000285	3.73e-06	7.63	0.000	.0000212	.00003
Nov	-.0521651	.0036593	-14.26	0.000	-.0593471	-.04498
Dec	-.0257319	.0032728	-7.86	0.000	-.0321553	-.01930
Feb	-.0128014	.0032977	-3.88	0.000	-.0192736	-.00632
Mar	-.0350132	.0036339	-9.64	0.000	-.0421452	-.02788
Sun	-.0006508	.0038418	-0.17	0.866	-.008191	.00688
Tue	.0012247	.0038415	0.32	0.750	-.0063148	.00876
Wed	-.0036608	.0038516	-0.95	0.342	-.01122	.00389
Thu	-.0087818	.0038512	-2.28	0.023	-.0163402	-.00122
Fri	-.0104976	.003861	-2.72	0.007	-.0180753	-.00291
Sat	-.0157523	.0038434	-4.10	0.000	-.0232956	-.00820
HS1011	-.0004719	.0036956	-0.13	0.898	-.0077249	.00678
HS1213	.0026394	.0036525	0.72	0.470	-.0045292	.0098
HS1314	.0241344	.0038261	6.31	0.000	.0166251	.03164
HS1415	.0265937	.003666	7.25	0.000	.0193988	.03378
hs1516	.0166879	.0035566	4.69	0.000	.0097075	.02366
_cons	.1009652	.0074985	13.46	0.000	.0862483	.11568

Department Attachment 3
Docket No. G008/M-16-571
CenterPoint Demand Entitlement Analysis

		Number of Firm Customers				Design Day Requirement			Total Entitlement Plus On-line Storage & Peak Shaving				Reserve Margin
		(1 A)	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
Docket No.	Heating Season	Actual Number of Jan. Customers	Projected DD Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dk)	Change from Previous Year	% Change From Previous Year	Total Entitlement (Dk)		Entitlement Change from Previous Year	% Change From Previous Year	Corrected Reserve Margin [(7)-(4)]/(4)
16-571	2016-2017*	n/a	850,572	9,437	1.12%	1,364,000	11,000	0.81%	1,369,470		13,519	1.00%	0.40%
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:		792,715	9,413	1.22%	1,260,019	12,026	0.98%	1,326,211		8,038	0.62%	5.39%

		Firm Peak Day Sendout			Per Customer Metrics				
		(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Docket No.	Heating Season	Firm Peak Day Sendout (Dk)	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 Sendout per DD # Customer (11)/(1)	Peak Day Sendout per Actual Customers (11)/(1 A)
16-571	2016-2017*	n/a	n/a	n/a	0.0064	1.6036	1.6101	n/a	n/a
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:	943,264	14,336	2.13%	0.0840	1.5910	1.6750	1.1964	1.2034

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.

Department Attachment 4
Docket No. G008/M-16-571
CenterPoint Rate Impacts

Residential	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2015)	October 2016 PGA	November 2016 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)	$3.4897	$2.9715	$2.9890	$2.9045	-16.77%	-2.25%	-2.83%	($0.0845)
Demand Cost of Gas (1)	$0.7646	$0.8505	$0.8267	$0.8064	5.47%	-5.19%	-2.46%	($0.0203)
Commodity Margin (2) (3)	$1.8458	$1.9341	$1.9479	$1.9479	5.53%	0.71%	0.00%	$0.0000
Total Cost of Gas	$6.1001	$5.7561	$5.7636	$5.6588	-7.23%	-1.69%	-1.82%	($0.1048)
Average Annual Usage (Dk)	100	100	100	100				
Average Annual Total Cost of Gas	$610.01	$575.61	$576.36	$565.88	-7.23%	-1.69%	-1.82%	($10.48)
Average Annual Total Demand Cost of Gas								($2.03)

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2015)	October 2016 PGA	November 2016 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)	$4.0181	$2.9715	$2.9890	$2.9045	-27.71%	-2.25%	-2.83%	($0.0845)
Demand Cost of Gas (1)	$0.7646	$0.8505	$0.8267	$0.8064	5.47%	-5.19%	-2.46%	($0.0203)
Commodity Margin	$1.4129	$1.5012	$1.5150	$1.5150	7.23%	0.92%	0.00%	$0.0000
Total Cost of Gas	$6.1956	$5.3232	$5.3307	$5.2259	-15.65%	-1.83%	-1.97%	($0.1048)
Average Annual Usage (Dk)	80	80	80	80				
Average Annual Total Cost of Gas	$495.65	$425.86	$426.46	$418.07	-15.65%	-1.83%	-1.97%	($8.38)
Average Annual Total Demand Cost of Gas								($1.62)

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2015)	October 2016 PGA	November 2016 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)	$4.0181	$2.9715	$2.9890	$2.9045	-27.71%	-2.25%	-2.83%	($0.0845)
Demand Cost of Gas (1)	$0.7646	$0.8505	$0.8267	$0.8064	5.47%	-5.19%	-2.46%	($0.0203)
Commodity Margin	$1.3329	$1.4232	$1.4370	$1.4370	7.81%	0.97%	0.00%	$0.0000
Total Cost of Gas	$6.1156	$5.2452	$5.2527	$5.1479	-15.82%	-1.86%	-2.00%	($0.1048)
Average Annual Usage (Dk)	2,860	2,860	2,860	2,860				
Average Annual Total Cost of Gas	$17,490.62	$15,001.27	$15,022.72	$14,722.99	-15.82%	-1.86%	-2.00%	($299.73)
Average Annual Total Demand Cost of Gas								($58.06)

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-15-728 & GR-15-524)	Last Demand Change (G008/M-15-644) (Dec 2015)	October 2016 PGA	November 2016 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)	$3.9806	$2.9715	$2.9890	$2.9045	-27.03%	-2.25%	-2.83%	($0.0845)
Demand Cost of Gas (1)	$0.7646	$0.8505	$0.8267	$0.8064	5.47%	-5.19%	-2.46%	($0.0203)
Commodity Margin	$1.3969	$1.4852	$1.4990	$1.4990	7.31%	0.93%	0.00%	$0.0000
Total Cost of Gas	$6.1421	$5.3072	$5.3147	$5.2099	-15.18%	-1.83%	-1.97%	($0.1048)
Average Annual Usage (Dk)	14,300	14,300	14,300	14,300				
Average Annual Total Cost of Gas	$87,832.03	$75,892.96	$76,000.21	$74,501.57	-15.18%	-1.83%	-1.97%	($1,498.64)
Average Annual Total Demand Cost of Gas								($290.29)

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	-$0.0845	-2.83%	-$0.0203	-2.46%	($2.03)	($10.48)	-1.82%
Commercial/Industrial Firm A	-$0.0845	-2.83%	-$0.0203	-2.46%	($1.62)	($8.38)	-1.97%
Commercial/Industrial Firm B	-$0.0845	-2.83%	-$0.0203	-2.46%	($58.06)	($299.73)	-2.00%
Commercial/Industrial Firm C	-$0.0845	-2.83%	-$0.0203	-2.46%	($290.29)	($1,498.64)	-1.97%

(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).