December 30, 2019 **PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G008/M-19-278

Dear Mr. Wolf:

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

> CenterPoint Energy Minnesota Gas' (CenterPoint or the Company) Request for Change in Demand Units (Petition).

The Petition was filed on May 1, 2019 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 May 1, 2019 and November 1, 2019. The Department is available to answer any questions that the Minnesota Public Utilities Commission may have.

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

**PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED**

Docket No. G008/M-19-278

## I. INTRODUCTION

Pursuant to Minnesota Rules 7825.2910, subpart 2,[1] CenterPoint Energy Minnesota Gas (CenterPoint, CPE, or the Company) filed a petition requesting a change in demand[2] units (Petition) on May 1, 2019. The Company also provided information and discussion regarding proposed changes to its short-term winter storage contract and its long-term Natural Gas Pipeline Company (NGPL) storage contract. The demand entitlement levels reported in the Petition are proposed as of May 2019 and are not necessarily 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. On November 1, 2019, CenterPoint filed a supplement (Supplemental Filing) to its original Petition detailing final entitlement purchases and demand costs for the upcoming heating season. In this Supplemental Filing, CenterPoint noted that it updated expected annual costs but it did not change its proposed entitlement level from the original Petition. CenterPoint also explained that its new contract with Northern Natural Gas (Northern) does not have T-12 Base and T-12 Variable service.[3]

In its Petition, CenterPoint requested that the Minnesota Public Utilities Commission (Commission) approve two increases in the Company's overall demand costs, a $1.4 million increase effective May 1, 2019 and a $24.2 million increase effective November 1, 2019. CenterPoint did not propose a change in the total level of entitlement for May 1, 2019, but the increase in costs reflects implementation of new storage contracts, a summer capacity release credit, and correction of its Viking Pipeline entitlement expenses. The Company does propose a change in the total level of entitlement effective November 1, 2019 and an increase in costs to reflect changes in demand rates associated with CenterPoint's renegotiated long-term agreement with Northern.[4] CenterPoint requested that the Commission approve an increase in the Company's overall level of contracted pipeline capacity of 41,688 Dekatherms (Dkt) per day.[5] As part of these entitlement changes, the Company also reported proposed changes in its propane peaking capacity. CenterPoint stated that available output from its

[1] "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] Supplemental Filing, Page 1.
[4] Petition, Page 1.
[5] Petition, Page 4.

River Plant is decreased for the 2019-2020 and 2020-2021 heating seasons because of distribution system replacement work.[6] CenterPoint stated that the entitlements were added to reflect the addition of the Company's first growth election under its new Northern contract. The Company also stated that these entitlements were both winter and summer entitlements and for delivery to both outstate and metro Town Border Stations (TBS).

As noted above, CenterPoint made changes to the amount of storage contracted. Storage does not directly impact daily entitlements, but is an important tool to secure natural gas supply. In the Petition, the Company stated that it renegotiated two storage contracts and proposed changes in the allocation of these storage contract costs between the demand and commodity portion of the monthly Purchased Gas Adjustment (PGA). The Minnesota Department of Commerce, Division of Energy Resources (Department) discusses these storage contracts further in Section II.A below.

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

## II. DEPARTMENT ANALYSIS

The Department's analysis of the Company's request includes the following:

- CenterPoint's proposed storage contracts;
- The proposed changes to the entitlement level and to non-capacity items;
- The design-day requirement;
- The reserve margin;
- Distribution planning; and
- The PGA cost recovery proposals.

The Department discusses these topics separately below.

### *A. REVIEW OF CENTERPOINT'S PROPOSED STORAGE CONTRACTS*

In its Petition, the Company noted that it renegotiated two storage contracts, both effective May 1, 2019. Although storage contracts do not impact the overall level of available entitlement, these contracts provide flexibility in terms of access to gas supplies and price of gas deliveries. The Department discusses and reviews each of these storage contracts separately.

The first contract is the Company's BP Canada Marketer Storage (BP Storage) contract. CenterPoint explained that this contract replaces its existing short-term winter storage contract with Tenaska. In July 2018, the Company issued a Request for Proposal (RFP) to 12 large suppliers seeking bids on storage contracts to replace the soon-to-be expired Tenaska contract. BP Canada and Tenaska were

[6] Petition, Page 3.

the only parties that responded to the RFP and, after review, CenterPoint concluded that BP Canada's bid was most favorable. This new BP Storage contract results in an additional annual cost to ratepayers of $2.4 million. CenterPoint also noted that this contract maintains the same allocation of demand costs previously approved for the Tenaska contract in Docket No. G008/M-16-571.[7]

Given the increase in costs to ratepayers, the Department issued discovery requesting that the Company provide all RFP information and discussion supporting its decision to procure the BP Storage contract. CenterPoint provided its response in **Trade Secret** Department Information Request No. 1.[8] In this response, the Company provided the various proposals from the counterparties and a detailed discussion of its rationale for choosing the BP Storage contract. Specifically, the Department notes that the BP Storage contract **[TRADE SECRET DATA HAS BEEN EXCISED].** Based on its review, the Department concludes that CenterPoint's storage contract procurement decision was cost effective.

The second contract is the Company's NGPL storage contract. This storage contract represents a renegotiation of CenterPoint's existing contract with NGPL, which is an existing long-term storage contract. CenterPoint explained that due to the lack of alternative storage service of the size and type required at a comparable cost, without extensive additional upstream costs, the Company concluded that NGPL was the most economic storage option available to ratepayers. CenterPoint also noted various benefits that the renegotiated contract accomplishes (*e.g.,* rate control, flexibility, simplified contract structure). The renegotiated contract runs from November 2019 to April 2034, and CenterPoint noted that this agreement provides for 15.8 Bcf of gas storage capacity and maintains the same maximum firm daily withdrawal rights of 210,986 Dkt/day from its previous NGPL contract. The Company also explained that the contract includes firm daily deliverability rights on Northern and provides much flexibility to meet daily load swings and the ability to hedge prices. CenterPoint further noted that the renegotiated contract increases annual demand costs by $2.7 million for 2019, but the longer-term net impact is an increase of approximately $869,000 per year beginning in February 2020 when certain previously agreed upon projects on NGPL are completed. Despite an increase in total demand cost with the new agreement, CenterPoint also noted that the fixed rate agreed upon with NGPL is lower than comparable annual transportation or storage costs.

Based on its review, the Department concludes that CenterPoint's decision to renegotiate its existing NGPL contract is not unreasonable. Although annual demand costs increase with this contract, the additional costs are minor relative to total demand costs and the long-term benefits provided to ratepayers are important.

---

[7] Petition, Page 1.
[8] **Trade Secret** Department Attachment 2.

### *B. PROPOSED CHANGES TO THE ENTITLEMENT LEVEL AND TO NON-CAPACITY ITEMS*

#### *1. Changes to the Entitlement Level*

As indicated in Department Attachment 1 and noted above, the Company proposed to increase its entitlement level from the prior heating season, as follows:

**Table 1: CenterPoint's Total Entitlement Levels**

| Previous Entitlement (Dkt) | Proposed Entitlement (Dkt) | Entitlement Changes (Dkt) | % Change from Previous Year |
|---|---|---|---|
| 1,409,596 | 1,451,284 | 41,688 | 2.96% |

Based on its design-day and reserve margin analyses in Sections B.3 and B.4 below, the Department concludes that CenterPoint's proposed level of demand entitlement is appropriate and is likely sufficient to ensure firm reliability on a peak day.

#### *2. Changes to Non-Capacity Items*

As discussed in Section II.A above, CenterPoint renegotiated its NGPL storage contract and initiated a new short-term storage contract with BP Canada. These contracts do not impact CenterPoint's total entitlement level, but they do impact demand costs and can be used as part of an integrated hedging plan to reduce baseload winter gas purchases and potentially lower the number of hedging instruments.

In addition to renegotiating its NGPL storage contract, CenterPoint also proposed an adjustment to its allocation of NGPL cost between the demand and commodity portion of the PGA. This reallocation is important because all sales customers pay the commodity portion of the PGA while, typically, only firm customers pay the demand portion of the PGA. CenterPoint stated that the Commission required CenterPoint in previous demand entitlement Orders to assign part of the demand portion of the NGPL storage contract to Small Volume Dual Fuel customers through a winter commodity surcharge.[9] In that Order, the Commission required CenterPoint to assign 65.69 percent of NGPL cost to Firm and Small Dual Fuel customers and 34.31 percent to commodity costs; as such, 34.31 percent of costs are recovered from all sales service customers.

According to CenterPoint, its proposed reallocation of NGPL costs is meant to streamline cost assignment of the new NGPL contract and recognize that Small Volume Dual Fuel customers are expected to curtail during times of constraint. The Company proposed to change the demand/commodity allocation to a 50/50 percent split which, in CenterPoint's assessment, reflects equal responsibility for storage costs and shifts more of the total contract to the commodity portion of the PGA. In addition, transitioning to a 50/50 split would streamline the administration of this contract

[9] February 28, 2010 Order in Docket Nos. G008/M-07-561 and G008/M-11-1078.

by removing the existing secondary demand allocation. As noted above, the costs of the renegotiated NGPL contract is $2.7 million greater than the existing NGPL contract, therefore, the Company's new allocation proposal assigns approximately $1.3 million less to demand costs.

The Department reviewed CenterPoint's proposed reallocation of NGPL costs and concludes that the proposal is reasonable at this time. The 50/50 split in costs acknowledges the fact that storage contracts benefit all sales service customers by allowing the local distribution company (LDC) to access gas during the summer months, which is typically lower priced than gas available during the heating season, while also recognizing that non-firm customers are subject to curtailment.

As has been done since the 2011 demand entitlement filing, 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.

### *C. DESIGN-DAY REQUIREMENT*

#### *1. Design-Day Requirement*

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

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 2013 to March 2019. CenterPoint used heating degree days (HDDs) and the squared value of HDDs (HDD2) 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 2013 to March 2019 period. The HDD2 factor 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 HDD2 are both appropriately 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. To the extent sufficient data exist, CenterPoint's approach 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 existing firm customers; therefore, if the Company had 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 2013 to March 2019. CenterPoint's combined analyses resulted in a design-day estimate of 1,332,387 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 1,399,072 Dkt/day, which is 25,885 Dkt/day greater than the design-day estimate in last year's demand entitlement filing. The Company stated that it made the upper bound 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 estimation process is complex since peak-day use can be impacted by many different factors. Although weather (HDDs) is the primary factor behind peak-day use, the ultimate result may also depend upon influences such as the day of the week and when, during a cold spell, the event occurs. CenterPoint's proposed design-day estimate is based on an analysis that only incorporates the impacts of weather and does not contemplate other factors, such as: day of the week, month, and heating season. In other words, CPE's analysis assumes that all days are equal. The Department conducted alternative regression analyses in past demand entitlement filings that investigated potential impacts from these other factors. CenterPoint conducted a similar alternate analysis in this proceeding to validate the results of its proposed design-day results. The results of these alternate analyses were similar to the Company's recommended regression results and generally support CenterPoint's proposed design-day analysis.[10]

Below, the Department discusses its alternative analysis that incorporates both weather and non-weather factors.

*2. Department's Alternative Design-Day Analysis*

The Department's alternative analysis was based on the same period as CenterPoint's and included HDDs and HDD2 along with factors that account for month, day of the week, and heating season. Including these additional factors is 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.[11] The Department identified the factors with the greatest

[10] Petition, Exhibit B7.
[11] Department Attachment 3.

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 alternative approach, the additional regression factors increased the projected design day by a small amount, from CenterPoint's 1,332,387 Dkt/day figure to approximately 1,352,836 Dkt/day as calculated using the Department's model. The Department's results are within the confidence interval from the Company's design-day analysis results.

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 estimated a design day of approximately 1,497,613 Dkt/day, which is greater than CenterPoint's upper-bound result of 1,399,072 Dkt/day. The result of the Department's upper-bound analysis is also greater than CenterPoint's entitlement level inclusive of physical reserves (1,435,000 Dkt/day) which suggests that the Company may have insufficient capacity to serve firm customers on a peak day.

The Department notes, however, that caution should be exercised regarding the conclusion that CenterPoint may have insufficient capacity to meet peak-day use because the basis for this conclusion is purely statistical. As noted above, the Department's alternative analysis uses additional factors (*i.e.,* day of the week, month, heating season) that have the potential to impact consumption. The worst-case scenario involving all factors is an unlikely scenario. The Department also notes that its alternative analysis has greater statistical variability, all else being equal, than the Company's analysis because the Department's analysis uses a greater number of independent factors to estimate peak-day consumption. This variability is illustrated by the larger difference in the upper bound coefficients in the regression analysis relative to the Company's analysis and is not entirely unexpected.

After analyzing its upper-bound estimate, the Department does not believe this is a likely result nor does this result, on its own, suggest that CenterPoint has insufficient capacity to serve firm customers on a peak day. This conclusion is supported to some degree by the fact that CenterPoint's system performed well during the 2018-2019 heating season when near design-day conditions occurred. The Company's use of an upper-bound is meant to add an additional layer of security over the point estimate to ensure peak-day reliability. Since the point estimates of the two approaches are similar (CenterPoint's 1,332,387 Dkt/day and the Department's 1,352,836 Dkt/day), the Department concludes that the Department's upper-bound estimate for this heating season may not be a reasonable basis for drawing any conclusions regarding CPE's design day due to the model specification used. As noted above, the additional determinants used in the alternative analysis increased the statistical volatility of the results. Given this concern, the Department conducted additional analysis to determine whether CenterPoint's peak-day calculations are reasonable.

During the last heating season, CenterPoint's system experienced the coldest weather conditions since the 1995-1996 heating season, which is the basis for the Company's planning objective. The weather conditions experienced in late January 2019 were close to design-day conditions and provide the Department with the ability to test whether CenterPoint's design-day estimates are sufficient to ensure firm reliability on a Commission peak day of -25F on average for 24 hours. 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 approximately 1,332,843 Dkt. This result is 26,332 Dkt, or 2.0 percent, greater than the regression-estimated design-day figure of 1,306,511 Dkt calculated in last year's demand entitlement filing. However, this result is 40,344 Dkt, or 3.0 percent, lower than the upper-bound estimate of 1,373,187 Dkt used by the Company to determine its total entitlement level in last year's demand entitlement filing. This analysis suggests that CenterPoint's approach to calculating its design-day is likely sufficient to ensure reliability, and the Company's decision to use the upper-bound approach is warranted since estimated throughput was greater than the design-day estimate.

### *3. Design-Day Conclusions*

The Department's review of historical observations and data underscore the inherent difficulty with estimating peak-day consumption and the importance of an adequate reserve margin, as discussed further in Section D below. Based on its review of the Company's results, the Department results, and CenterPoint's performance during near design-day conditions in the 2018-2019 heating season, the Department concludes that CenterPoint's design-day analysis and assumptions are acceptable and appropriate for determining peak-day consumption for the upcoming (at the time of the analysis) heating season. CenterPoint's use of the upper-bound threshold was reasonable since its result was more in line with actual outcomes during the cold weather event during the 2018-2019 heating season. This approach also provides additional bias toward reliability in the event of a peak day event.

The Department recommends that the Commission accept the design-day level proposed by CenterPoint in this proceeding. The Department also recommends that CenterPoint continue to conduct additional analyses, similar to what was provided in the Petition's Exhibit B7, regarding its design-day calculations in future demand entitlement filings. As discussed above, these additional analyses are helpful and provide additional support for the Company's design-day calculations or may be a guide if there are issues with CenterPoint's analysis in the future.

## *D. RESERVE MARGIN*

As shown below, and in Department Attachment 1, CenterPoint's proposed reserve margin is approximately 1.13 percent inclusive of physical reserves and 3.74 percent without physical reserves:

**Table 2--CenterPoint Reserve Margin**

| Total Entitlement (Dkt) | Design-Day Estimate (Dkt) | Difference (Dkt) | Reserve Margin (%) | Percentage Point Change From Prior Year |
|---|---|---|---|---|
| 1,451,284 | 1,435,000 | 16,284 | 1.13% | 1.13% |
| **Total Entitlement (Dkt)** | **Design-Day Estimate without reserve (Dkt)** | **Difference (Dkt)** | **Reserve Margin (%)** | **Percentage Point Change From Prior Year** |
| 1,451,284 | 1,399,000 | 52,284 | 3.74% | 1.14% |

Both the Company's total entitlement level and estimated design-day increased when compared to the prior year. Since CenterPoint's total entitlement level increased at a greater level than the estimated design-day level, it resulted in an increase in the Company's proposed reserve margin compared to last heating season. The Department notes that the Company's proposed reserve margin, either with or without physical reserves, remains relatively low. However, the Department is encouraged that the reserve margin increased relative to last year's filing.

Physical reserves included in the Company's total entitlement level are inclusive of peak shaving volumes. The amount of peak shaving volumes built into the demand entitlement level is based on a percentage of actual peak shaving capacity, rather than the total capacity level, because the full amount of peak shaving capacity may be unavailable. This adjustment accounts for the fact that there may be a failure of a peaking plant or that CenterPoint may have used peak shaving earlier in the heating season, prior to a peak day, and then was unable to replenish volumes at the peak shaving facility. However, if CenterPoint did not call on peak shaving or was able to replenish capacity, additional volumes may be available to serve firm customers on a peak day. In the event that no peak shaving is available on the 90 HDD peak day, then CenterPoint's operational reserve margin is the lower figure noted in Table 2 above.

Based on its analysis, the Department concludes that, although CenterPoint's reserve margin remains low, it is likely sufficient to ensure firm reliability on a peak day. To the extent possible, the Department requests that the Company continue to explore cost-effective means of increasing its reserve margin in future demand entitlement filings.

### *E. DISTRIBUTION PLANNING*

In recent demand entitlement filings, the Department requested information from CenterPoint, and conducted analysis, regarding the Company's distribution planning and the integration of electric generation onto the CenterPoint system. In last year's demand entitlement filing, the Department concluded that the Company's current planning approach is reasonable and does not represent a negative impact to ratepayers or reliability. In response to the cold weather event in January 2019, the Commission opened an investigation in Docket No. E,G999/CI-19-160 that also reviewed utility response to cold weather and system reliability. As noted above, and discussed at length in Docket No. E,G999/CI-19-160, the Company did not experience reliability or deliverability issues during the cold weather event in late January 2019.

Although not typically discussed in demand entitlement filings, distribution planning is an important part of providing reliable service to ratepayers. The procurement of capacity in the demand entitlement is meant to satisfy total daily firm need on a peak day, while distribution planning is designed to ensure sufficient capacity is available to meet maximum gas need at a particular time and location. Given the potential for reliability issues during an extreme cold event, the Department issued discovery in an effort to understand CenterPoint's distribution planning assumptions. In its response to Department Information Request No. 2, the Company stated that it uses the same weather assumption in both its distribution planning and design-day analyses.[12] This response was somewhat concerning because the weather assumptions relevant to distribution planning should reflect average temperatures, while the coldest temperature is more relevant to design-day estimates; as such, the Department requested clarification of this response. In response to informal discovery, CenterPoint clarified that the weather assumptions into the two models are different but are related to each other.[13] In particular, CenterPoint noted that it uses the coldest temperature from the planning objective day when constructing its distribution planning model.

The Department appreciates the Company's explanation and clarification of its distribution planning assumptions. Based on this information, the Department concludes that CenterPoint's planning assumptions are acceptable at this time.

### *F. PGA COST RECOVERY PROPOSAL*

The demand entitlement amount listed in Department Attachment 6 represents the demand costs for which firm customers have been paying beginning May 1, 2019 and Department Attachment 7 represents the demand costs for which firm customers have been paying beginning November 1, 2019, subject to the Commission's approval in this matter. In its Petition, CenterPoint compared its April 2019 PGA to its May 2019 PGA to estimate the impact of its renegotiated storage contracts. These contracts result in an increase in demand costs of approximately $0.0125 per Dkt for the Residential Class.[14] In its Supplemental Filing, CenterPoint compared its October 2019 PGA to its estimated November 2019 PGA to estimate the impact of its increased entitlement levels. These additional entitlements result in an increase in demand costs of approximately $0.2185 per Dkt for the Residential Class.[15] As shown in Department Attachments 6 and 7, the Department replicated CenterPoint's analysis and found the same result. CenterPoint's proposed changes for May 2019 and November 2019 result in the following, combined annual rate impacts:

---

[12] Department Attachment 4.
[13] Department Attachment 5.
[14] Petition, Exhibit B4.
[15] Supplemental Filing, Exhibit B4.

- Annual demand cost increase of $23.10, or approximately 26.87 percent, for the average Residential customer consuming 100 Dkt annually;
- Annual demand cost increase of $18.48, or approximately 26.87 percent, for the average Commercial/Industrial Firm A customer consuming 80 Dkt annually;
- Annual demand cost increase of $660.66, or approximately 26.87 percent, for the average Commercial/Industrial Firm B customer consuming 2,860 Dkt annually; and
- Annual demand cost increase of $3,303.30, or approximately 26.87 percent, for the average Commercial/Industrial Firm C customer consuming 14,300 Dkt annually.

Based on its analysis, the Department recommends that the Commission approve the proposed demand costs with effective dates of May 1, 2019 and November 1, 2019.

## III. DEPARTMENT CONCLUSIONS AND RECOMMENDATIONS

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

- Approve CenterPoint's proposed level of demand entitlement and proposed recovery of associated demand costs effective May 1, 2019 and November 1, 2019; and
- Accept the design-day level proposed by CenterPoint.

/ja

Department Attachment 1
Docket No. G008/M-19-278
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) |
| 19-278 | 2019-2020 | n/a | 884,564 | 19,211 | 2.22% | 1,435,000 | 26,000 | 1.85% | 1,451,284 | | 41,688 | 2.96% | 1.13% |
| 18-462 | 2018-2019 | 868,105 | 865,353 | 8,261 | 0.96% | 1,409,000 | 6,000 | 0.43% | 1,409,596 | | 0 | 0.00% | 0.04% |
| 17-533 | 2017-2018 | 858,548 | 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: | | 804,760 | 9,732 | 1.24% | 1,284,595 | 13,966 | 1.10% | 1,341,887 | | 11,243 | 0.85% | 4.65% |

| | | 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) |
| 19-278 | 2019-2020 | n/a | n/a | n/a | 0.0184 | 1.6223 | 1.6407 | n/a | n/a |
| 18-462 | 2018-2019 | 1,253,519 | 163,897 | 15.04% | 0.0007 | 1.6282 | 1.6289 | 1.4486 | 1.4440 |
| 17-533 | 2017-2018 | 1,089,622 | 110,691 | 11.31% | 0.0077 | 1.6369 | 1.6446 | 1.2713 | 1.2691 |
| 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: | 970,613 | 27,063 | 3.22% | 0.0726 | 1.5970 | 1.6696 | 1.2120 | 1.2186 |

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.

# State of Minnesota
## Minnesota Department of Commerce

### Utility Information Request

Docket Number: G-008/M-19-278 - Demand Entitlement — Date of Request: 6/19/2019
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 7/1/2019

Analyst Requesting Information: Adam Heinen

Type of Inquiry: Other

***If you feel your responses are trade secret or privileged, please indicate this on your response.***

| Request No. | |
|---|---|
| DOC 001 P | Topic: Storage Contracts<br><br>Reference(s): Petition Pages 1 and 2<br><br>A. Please provide the executed contracts for both CenterPoint's BP Canada Marketer Storage Contract and its Natural Gas Pipeline Storage Contract.<br><br>B. Please provide any, and all, bid information submitted by BP Canada and Tenaska and a detailed explanation of the reasons why CenterPoint accepted the BP Canada bid.<br><br>If this information has already been provided in initial petition or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).<br><br>**Response:**<br><br>**PUBLIC DOCUMENT -- TRADE SECRET INFORMATION HAS BEEN REDACTED.**<br><br>A. Please see the attached file(s) containing CenterPoint Energy's contracts for the storage services noted. All attachment files are Non-Public and not included in this Public response.<br><br>CenterPoint Energy has designated the <u>attached documents' entire contents as trade secret</u>. The documents meet the definition of trade secret in Minn. Stat. § 13.37, subd. 1(b), as follows: (1) the documents were supplied by |

Response By: Marie Doyle
Title: Regulatory Analyst
Department: Regulatory
Telephone: 612-321-5078

CenterPoint Energy, the affected organization; (2) CenterPoint Energy has taken all reasonable efforts to maintain the secrecy of the documents, including protecting them from disclosure in this proceeding; and (3) the documents derive independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from their disclosure or use.

In accordance with Minn. Rule 7829.0500, Subp. 3, CenterPoint Energy furnishes the following description of the documents:

Nature of the Material: *Fully Executed Contracts – PDF versions*

Authors: *BP Canada and NGPL*

General Import: *Documents are what were requested in the Information Request*

Date the Documents were Prepared:

- *BP Canada: August 16, 2018*
- *NGPL: July 26, 2018*

FILES INCLUDED:

- A_1_BP Canada NON PUBLIC 2018 Final.pdf
- A_2a_CENTERPOINT MINNESOTA-NGPL NON PUBLIC NSS KT 150028.pdf
- A_2B_CENTERPOINT MINNESOTA-NGPL NON PUBLIC NSS KT 150030.pdf
- A_2a_CENTERPOINT MINNESOTA-NGPL NON PUBLIC FTS KT 150026.pdf

B. Please see the attached files containing CenterPoint Energy's bid information/explanations. All attachment files are Non-Public and not included in this Public response.

CenterPoint Energy has designated the documents' entire contents as trade secret. The documents meet the definition of trade secret in Minn. Stat. § 13.37, subd. 1(b), as follows: (1) the documents were supplied by

Response By: Marie Doyle
Title: Regulatory Analyst
Department: Regulatory
Telephone: 612-321-5078

CenterPoint Energy, the affected organization; (2) CenterPoint Energy has taken all reasonable efforts to maintain the secrecy of the documents, including protecting them from disclosure in this proceeding; and (3) the documents derive independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from their disclosure or use.

In accordance with Minn. Rule 7829.0500, Subp. 3, CenterPoint Energy furnishes the following description of the documents:

Nature of the Material: *RFP, bids from from Tenaska and BP Canada, CNP Evaluation matrix*

Authors: *CenterPoint Energy - RFP (July 2018) and Summary of Bids*
*Tenaska - bids and BP Bids*

General Import: *Documents provide back-up documentation of bids submitted and Company evaluation*

Date the Documents were Prepared:

- *B_Marketer Storage RFP July 2018 NON PUBLIC.pdf: July 3, 2018*
- *BP Canada: July 2018*
- *Tenaska: July 2018*
- *CenterPoint Energy: July 3, 2018 and July 2018*

CenterPoint Energy has attached a copy of the Bid Request "B_Marketer Storage RFP July 2018 NON PUBLIC.pdf" to this response. As noted in the document, on July 3, 2018, CenterPoint requested proposals for storage service to provide natural gas deliveries to CenterPoint's receipt points into Northern Natural Gas Company (NNG) during the winter months of November through March which will be priced at summer index. The request for proposal (RFP) was sent via email to 12 preferred suppliers. Two suppliers responded on July 24, 2018.

CenterPoint Energy also attaches four documents (also NON-PUBLIC) that include the bids provided. Due to the complexity of this storage service, CenterPoint Energy received multiple options from both BP Canada and Tenaska Marketing Ventures which are detailed in the "Summary of Bids-Marketer Storage Nov19-Mar22 NON PUBLIC.pdf" file.

Bids received are attached in four files:

Response By: Marie Doyle
Title: Regulatory Analyst
Department: Regulatory
Telephone: 612-321-5078

1. B_BP Canada Bids Options 1 to 3 NON PUBLIC.pdf
2. B_BP Canada Bid #2 Opt 4 and 5 NON PUBLIC.pdf
3. B_Tenaska Bid Option 1 NON PUBLIC.pdf
4. B_Tenaska Bid # 2 Options 2-4 NON PUBLIC.pdf

The options vary in total storage volumes, daily withdrawal limits, NNG receipt points, and timing of demand and commodity payments.

**Non-Public Document -- Contains Trade Secret Information:**

CenterPoint Energy Minnesota Gas has designated information in this document as trade secret. The information meets the definition of trade secret in Minn. Stat. 13.37 subd.1(b) as follows: (1) the information was supplied by CenterPoint Energy Minnesota Gas, the affected organization; (2) CenterPoint Energy Minnesota Gas has taken all reasonable efforts to maintain the secrecy of the information, and (3) the protected information contains operating information which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

**[TRADE SECRET BEGINS...**

Response By: Marie Doyle
Title: Regulatory Analyst
Department: Regulatory
Telephone: 612-321-5078

**...TRADE SECRET ENDS.]**

Response By: Marie Doyle
Title: Regulatory Analyst
Department: Regulatory
Telephone: 612-321-5078

```
. regress upc hdd hdd2 sun mon tue wed thu fri sat nov dec jan feb mar hs1314 hs1415 hs1516 hs1617
>  hs1718 hs1819
note: mon omitted because of collinearity
note: feb omitted because of collinearity
note: hs1314 omitted because of collinearity
```

| Source | SS | df | MS |
|---|---|---|---|
| Model | 52.9210311 | 17 | 3.11300183 |
| Residual | .833132055 | 889 | .000937156 |
| Total | 53.7541631 | 906 | .059331306 |

| | |
|---|---|
| Number of obs | = 907 |
| F( 17, 889) | = 3321.75 |
| Prob > F | = 0.0000 |
| R-squared | = 0.9845 |
| Adj R-squared | = 0.9842 |
| Root MSE | = .03061 |

| upc | Coef. | Std. Err. | t | P>\|t\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| hdd | .0138029 | .0003434 | 40.20 | 0.000 | .013129 | .0144769 |
| hdd2 | .0000197 | 3.85e-06 | 5.12 | 0.000 | .0000122 | .0000273 |
| sun | -.0066616 | .0038048 | -1.75 | 0.080 | -.014129 | .0008058 |
| mon | 0 | (omitted) | | | | |
| tue | .0006507 | .0038148 | 0.17 | 0.865 | -.0068364 | .0081378 |
| wed | -.0036711 | .0038196 | -0.96 | 0.337 | -.0111676 | .0038253 |
| thu | -.0065144 | .0038192 | -1.71 | 0.088 | -.0140101 | .0009814 |
| fri | -.0116059 | .0038181 | -3.04 | 0.002 | -.0190994 | -.0041123 |
| sat | -.0200591 | .0038104 | -5.26 | 0.000 | -.0275374 | -.0125808 |
| nov | -.0359739 | .0035878 | -10.03 | 0.000 | -.0430155 | -.0289323 |
| dec | -.0076539 | .0032752 | -2.34 | 0.020 | -.0140819 | -.0012258 |
| jan | .0152007 | .0032625 | 4.66 | 0.000 | .0087975 | .0216038 |
| feb | 0 | (omitted) | | | | |
| mar | -.024576 | .0035234 | -6.98 | 0.000 | -.0314911 | -.017661 |
| hs1314 | 0 | (omitted) | | | | |
| hs1415 | .0031343 | .0035599 | 0.88 | 0.379 | -.0038525 | .0101212 |
| hs1516 | -.0049837 | .0036959 | -1.35 | 0.178 | -.0122374 | .0022701 |
| hs1617 | .0080699 | .0036709 | 2.20 | 0.028 | .0008653 | .0152744 |
| hs1718 | .024495 | .0035682 | 6.86 | 0.000 | .0174919 | .0314981 |
| hs1819 | .0228831 | .0035554 | 6.44 | 0.000 | .0159051 | .0298611 |
| _cons | .0908396 | .0087421 | 10.39 | 0.000 | .0736821 | .1079971 |

```
. regress upc hdd hdd2 sun tue wed thu fri sat nov dec jan mar hs1415 hs1516 hs1617 hs1718 hs1819
```

| Source | SS | df | MS |
|---|---|---|---|
| Model | 52.9210311 | 17 | 3.11300183 |
| Residual | .833132055 | 889 | .000937156 |
| Total | 53.7541631 | 906 | .059331306 |

| | |
|---|---|
| Number of obs | = 907 |
| F( 17, 889) | = 3321.75 |
| Prob > F | = 0.0000 |
| R-squared | = 0.9845 |
| Adj R-squared | = 0.9842 |
| Root MSE | = .03061 |

| upc | Coef. | Std. Err. | t | P>\|t\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| hdd | .0138029 | .0003434 | 40.20 | 0.000 | .013129 | .0144769 |
| hdd2 | .0000197 | 3.85e-06 | 5.12 | 0.000 | .0000122 | .0000273 |
| sun | -.0066616 | .0038048 | -1.75 | 0.080 | -.014129 | .0008058 |
| tue | .0006507 | .0038148 | 0.17 | 0.865 | -.0068364 | .0081378 |
| wed | -.0036711 | .0038196 | -0.96 | 0.337 | -.0111676 | .0038253 |
| thu | -.0065144 | .0038192 | -1.71 | 0.088 | -.0140101 | .0009814 |
| fri | -.0116059 | .0038181 | -3.04 | 0.002 | -.0190994 | -.0041123 |
| sat | -.0200591 | .0038104 | -5.26 | 0.000 | -.0275374 | -.0125808 |
| nov | -.0359739 | .0035878 | -10.03 | 0.000 | -.0430155 | -.0289323 |
| dec | -.0076539 | .0032752 | -2.34 | 0.020 | -.0140819 | -.0012258 |
| jan | .0152007 | .0032625 | 4.66 | 0.000 | .0087975 | .0216038 |
| mar | -.024576 | .0035234 | -6.98 | 0.000 | -.0314911 | -.017661 |
| hs1415 | .0031343 | .0035599 | 0.88 | 0.379 | -.0038525 | .0101212 |
| hs1516 | -.0049837 | .0036959 | -1.35 | 0.178 | -.0122374 | .0022701 |
| hs1617 | .0080699 | .0036709 | 2.20 | 0.028 | .0008653 | .0152744 |
| hs1718 | .024495 | .0035682 | 6.86 | 0.000 | .0174919 | .0314981 |
| hs1819 | .0228831 | .0035554 | 6.44 | 0.000 | .0159051 | .0298611 |
| _cons | .0908396 | .0087421 | 10.39 | 0.000 | .0736821 | .1079971 |

```
. regress fsvolume hdd  hdd2 sun mon tue wed thu fri sat nov dec jan feb mar hs1314 hs1415 hs1516
> hs1617 hs1718 hs1819
note: mon omitted because of collinearity
note: feb omitted because of collinearity
note: hs1314 omitted because of collinearity
```

| Source | SS | df | MS |
|---|---|---|---|
| Model | 1.7030e+09 | 17 | 100177419 |
| Residual | 405424626 | 889 | 456045.699 |
| Total | 2.1084e+09 | 906 | 2327197.3 |

| | |
|---|---|
| Number of obs = | 907 |
| F( 17, 889) = | 219.67 |
| Prob > F = | 0.0000 |
| R-squared = | 0.8077 |
| Adj R-squared = | 0.8040 |
| Root MSE = | 675.31 |

| fsvolume | Coef. | Std. Err. | t | P>\|t\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| hdd | 70.92957 | 7.575007 | 9.36 | 0.000 | 56.06258 | 85.79655 |
| hdd2 | .0570941 | .0848511 | 0.67 | 0.501 | -.1094378 | .223626 |
| sun | -517.3633 | 83.93212 | -6.16 | 0.000 | -682.0915 | -352.6351 |
| mon | 0 | (omitted) | | | | |
| tue | 32.72003 | 84.1534 | 0.39 | 0.698 | -132.4425 | 197.8825 |
| wed | 33.33941 | 84.25833 | 0.40 | 0.692 | -132.029 | 198.7078 |
| thu | -68.33047 | 84.25075 | -0.81 | 0.418 | -233.684 | 97.02309 |
| fri | -370.0455 | 84.22613 | -4.39 | 0.000 | -535.3507 | -204.7402 |
| sat | -779.9905 | 84.05492 | -9.28 | 0.000 | -944.9597 | -615.0213 |
| nov | -213.0567 | 79.14572 | -2.69 | 0.007 | -368.3909 | -57.7224 |
| dec | -340.39 | 72.24994 | -4.71 | 0.000 | -482.1903 | -198.5896 |
| jan | -107.7878 | 71.97029 | -1.50 | 0.135 | -249.0393 | 33.46369 |
| feb | 0 | (omitted) | | | | |
| mar | -489.0824 | 77.72382 | -6.29 | 0.000 | -641.626 | -336.5388 |
| hs1314 | 0 | (omitted) | | | | |
| hs1415 | -486.5157 | 78.5306 | -6.20 | 0.000 | -640.6427 | -332.3888 |
| hs1516 | -959.511 | 81.53063 | -11.77 | 0.000 | -1119.526 | -799.4961 |
| hs1617 | -894.8208 | 80.97767 | -11.05 | 0.000 | -1053.75 | -735.8911 |
| hs1718 | -1034.908 | 78.71347 | -13.15 | 0.000 | -1189.394 | -880.4224 |
| hs1819 | -1292.025 | 78.43149 | -16.47 | 0.000 | -1445.957 | -1138.092 |
| _cons | 3463.01 | 192.8467 | 17.96 | 0.000 | 3084.522 | 3841.498 |

```
. regress fsvolume hdd  hdd2 sun tue wed thu fri sat nov dec jan mar hs1415 hs1516 hs1617 hs1718 h
> s1819
```

| Source | SS | df | MS |
|---|---|---|---|
| Model | 1.7030e+09 | 17 | 100177419 |
| Residual | 405424626 | 889 | 456045.699 |
| Total | 2.1084e+09 | 906 | 2327197.3 |

| | |
|---|---|
| Number of obs | = 907 |
| F( 17, 889) | = 219.67 |
| Prob > F | = 0.0000 |
| R-squared | = 0.8077 |
| Adj R-squared | = 0.8040 |
| Root MSE | = 675.31 |

| fsvolume | Coef. | Std. Err. | t | P>\|t\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| hdd | 70.92957 | 7.575007 | 9.36 | 0.000 | 56.06258 | 85.79655 |
| hdd2 | .0570941 | .0848511 | 0.67 | 0.501 | -.1094378 | .223626 |
| sun | -517.3633 | 83.93212 | -6.16 | 0.000 | -682.0915 | -352.6351 |
| tue | 32.72003 | 84.1534 | 0.39 | 0.698 | -132.4425 | 197.8825 |
| wed | 33.33941 | 84.25833 | 0.40 | 0.692 | -132.029 | 198.7078 |
| thu | -68.33047 | 84.25075 | -0.81 | 0.418 | -233.684 | 97.02309 |
| fri | -370.0455 | 84.22613 | -4.39 | 0.000 | -535.3507 | -204.7402 |
| sat | -779.9905 | 84.05492 | -9.28 | 0.000 | -944.9597 | -615.0213 |
| nov | -213.0567 | 79.14572 | -2.69 | 0.007 | -368.3909 | -57.7224 |
| dec | -340.39 | 72.24994 | -4.71 | 0.000 | -482.1903 | -198.5896 |
| jan | -107.7878 | 71.97029 | -1.50 | 0.135 | -249.0393 | 33.46369 |
| mar | -489.0824 | 77.72382 | -6.29 | 0.000 | -641.626 | -336.5388 |
| hs1415 | -486.5157 | 78.5306 | -6.20 | 0.000 | -640.6427 | -332.3888 |
| hs1516 | -959.511 | 81.53063 | -11.77 | 0.000 | -1119.526 | -799.4961 |
| hs1617 | -894.8208 | 80.97767 | -11.05 | 0.000 | -1053.75 | -735.8911 |
| hs1718 | -1034.908 | 78.71347 | -13.15 | 0.000 | -1189.394 | -880.4224 |
| hs1819 | -1292.025 | 78.43149 | -16.47 | 0.000 | -1445.957 | -1138.092 |
| _cons | 3463.01 | 192.8467 | 17.96 | 0.000 | 3084.522 | 3841.498 |

# State of Minnesota
## Minnesota Department of Commerce

**<u>Utility Information Request</u>**

Docket Number: G-008/M-19-278 - Demand Entitlement Date of Request: 9/25/2019
Requested From: CenterPoint Energy Minnesota Gas Response Due: 10/7/2019

Analyst Requesting Information: Adam Heinen

Type of Inquiry: Other

***If you feel your responses are trade secret or privileged, please indicate this on your response.***

| Request No. | |
|---|---|
| DOC 002 | Topic: Distribution Planning<br>Reference(s):<br><br>Please fully explain how the utility arrives at its weather assumption (*e.g.*, HDD, temperature) for distribution system planning purposes. As part of this explanation, please also identify the weather assumption used for each Town Border Station or City Gate on the utility's system.<br><br>If this information has already been provided in initial petition or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).<br><br>**Response:**<br><br>For CenterPoint Energy Minnesota Gas, the design day is defined as a 24-hour period of the greatest possible gas requirements to meet our firm customer needs. For design day conditions, the weather assumption is 90 heating degree days (HDDs) or (-25) degrees Fahrenheit average daily temperature. This assumption is based on a search of NOAA historical average daily temperatures at the Minneapolis/St. Paul International Airport weather station from 1900 to current, and represents an extreme that has been matched or exceeded three times in that period (matched as recently as 1996).<br><br>This response has been provided annually in the AAA – most recently in the G-999/AA-18-374 docket, request #4 Supply Portfolio, part B(1). In addition, this assumption is used in Design Day analysis provided in annual Demand Entitlement filings. |

Response By: Marie Doyle
Title: Lead Analyst, Regulatory & Rates
Department: Regulatory
Telephone: 612-321-5078

The same weather assumption is used in Town Border station/City Gate planning and distribution system planning.

Response By: Marie Doyle
Title: Lead Analyst, Regulatory & Rates
Department: Regulatory
Telephone: 612-321-5078

**From:** Doyle, Marie M.
**To:** Heinen, Adam (COMM)
**Cc:** Sudbury, Andrew T; Wiinamaki, John M.; Tollefson, Casey G
**Subject:** M-19-278: CPE Demand Entitlement - Follow up- Engineering models
**Date:** Tuesday, November 12, 2019 3:43:12 PM

---

Adam - See below for the Engineering Department's response to your inquiry, which I interpreted as:
Q: I got the attached voicemail as a follow-up from Adam Heinen. I've attached the Company's response he is referring to.

I called him to get clarification - he seems to want the temperature assumption(s) used on hourly modeling. He asked if we assume it never gets colder than -25 deg F, to which I explained that is a 24 hour average temperature, not an absolute coldest temp. He explained it could be like a "Venn Diagram", where we have several different assumptions that overlap (i.e. the-25 deg F), but that he is looking for the assumptions used in worst-case/absolute coldest instantaneous or hourly cold?

A: System Modelling Assumptions:

The average daily temperature of -25 degrees is our design day temperature and has been the basis for planning our system for years. In 1996, an average daily temperature of -22.8 degrees was experienced. The low temperature on that day was -31 degrees and the high temperature was -12 degrees. Actual hourly flowrates and actual pressures experienced when the temperature was -31 degrees are used in network modeling. Flowrates and pressures are unique to each separate part of the distribution system, metro and outstate, and correlate with the diverse demand on each system. Hourly, peak demand flowrates and pressures are incorporated into the model for a specific system. Engineering has data and measurements from a variety of points around the distribution system.

During the winter of 2019 the coldest average daily temperature was -20 degrees. The low temperature on that day was -29. When modeling CenterPoint Energy's system, actual hourly flowrates are factored and modeled higher (using relative ratios) to reflect design day conditions. Globally, we adjust the system loads in the network model by a calculated percentage to represent and model design day conditions .

To validate our models, we monitor a significant number of pressure recording points throughout the metro and outstate areas during the heating season. Utilizing network models in conjunction with actual field data we can predict when a system is at a matured state and requires reinforcement.

Casey Tollefson, PE
Staff Engineer | Gas Engineering & System Integrity
612.321.5502
CenterPointEnergy.com

Call me if you'd like further information - Marie

Marie M. Doyle
Regulatory Analyst
612.321.5078
Marie.Doyle@CenterPointEnergy.com
505 Nicollet Mall, PO Box 59038, Mpls. MN 55379-0038

-----Original Message-----
From: Heinen, Adam (COMM) <adam.heinen@state.mn.us>
Sent: Friday, November 8, 2019 1:50 PM
To: Doyle, Marie M. <marie.doyle@centerpointenergy.com>
Cc: Sudbury, Andrew T <andrew.sudbury@centerpointenergy.com>

Subject: [External Email] RE: Follow up- Engineering models

EXTERNAL EMAIL

Thanks, Tuesday is just fine for a response. Oh, the deer opener, an annual tradition!

Adam Heinen
Public Utilities Rates Analyst
651-539-1825
mn.gov/commerce
Minnesota Department of Commerce
85 7th Place East, Suite 280 | Saint Paul, MN 55101



-----Original Message-----
From: Doyle, Marie M. <marie.doyle@centerpointenergy.com>
Sent: Friday, November 08, 2019 1:23 PM
To: Heinen, Adam (COMM) <adam.heinen@state.mn.us>
Cc: Sudbury, Andrew T <andrew.sudbury@centerpointenergy.com>
Subject: Follow up- Engineering models

Adam- wanted to let you know that my contacts in engineering are working on an explanation of our distribution modeling under peak conditions and weather assumptions.

I expect to have something for you on Tuesday (Nov 12) because folks are out of the office for deer hunting.
Marie

Sent from my iPhone

---



---

Department Attachment 6
Docket No. G008/M-19-278
CenterPoint Rate Impacts

| Residential | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | April 2019 PGA | May 2019 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) | $3.2426 | $3.4556 | $2.6303 | $2.6303 | -18.88% | -23.88% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8597 | $0.8722 | 9.24% | 1.45% | 1.45% | $0.0125 |
| Commodity Margin (2) (3) | $2.2201 | $2.1477 | $2.1477 | $2.1477 | -3.26% | 0.00% | 0.00% | $0.0000 |
| Total Cost of Gas | $6.2611 | $6.4630 | $5.6377 | $5.6502 | -9.76% | -12.58% | 0.22% | $0.0125 |
| Average Annual Usage (Dk) | 100 | 100 | 100 | 100 | | | | |
| Average Annual Total Cost of Gas | $626.11 | $646.30 | $563.77 | $565.02 | -9.76% | -12.58% | 0.22% | $1.25 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $1.25 |

| Commercial/Industrial Firm - A | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | April 2019 PGA | May 2019 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) | $3.2426 | $3.4556 | $2.6303 | $2.6303 | -18.88% | -23.88% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8597 | $0.8722 | 9.24% | 1.45% | 1.45% | $0.0125 |
| Commodity Margin | $2.2211 | $2.1649 | $2.1649 | $2.1649 | -2.53% | 0.00% | 0.00% | $0.0000 |
| Total Cost of Gas | $6.2621 | $6.4802 | $5.6549 | $5.6674 | -9.50% | -12.54% | 0.22% | $0.0125 |
| Average Annual Usage (Dk) | 80 | 80 | 80 | 80 | | | | |
| Average Annual Total Cost of Gas | $500.97 | $518.42 | $452.39 | $453.39 | -9.50% | -12.54% | 0.22% | $1.00 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $1.00 |

| Commercial/Industrial Firm - B | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | April 2019 PGA | May 2019 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) | $3.2426 | $3.4556 | $2.6303 | $2.6303 | -18.88% | -23.88% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8597 | $0.8722 | 9.24% | 1.45% | 1.45% | $0.0125 |
| Commodity Margin | $1.8293 | $1.7529 | $1.7181 | $1.7529 | -4.18% | 0.00% | 2.03% | $0.0348 |
| Total Cost of Gas | $5.8703 | $6.0682 | $5.2081 | $5.2554 | -10.47% | -13.39% | 0.91% | $0.0473 |
| Average Annual Usage (Dk) | 2,860 | 2,860 | 2,860 | 2,860 | | | | |
| Average Annual Total Cost of Gas | $16,789.06 | $17,355.05 | $14,895.17 | $15,030.44 | -10.47% | -13.39% | 0.91% | $135.28 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $35.75 |

| Commercial/Industrial Firm - C | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | April 2019 PGA | May 2019 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) | $3.2426 | $3.4556 | $2.6303 | $2.6303 | -18.88% | -23.88% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8597 | $0.8722 | 9.24% | 1.45% | 1.45% | $0.0125 |
| Commodity Margin | $1.6982 | $1.5795 | $1.5795 | $1.5795 | -6.99% | 0.00% | 0.00% | $0.0000 |
| Total Cost of Gas | $5.7392 | $5.8948 | $5.0695 | $5.0820 | -11.45% | -13.79% | 0.25% | $0.0125 |
| Average Annual Usage (Dk) | 14,300 | 14,300 | 14,300 | 14,300 | | | | |
| Average Annual Total Cost of Gas | $82,070.56 | $84,295.64 | $72,493.85 | $72,672.60 | -11.45% | -13.79% | 0.25% | $178.75 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $178.75 |

**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 | $0.0000 | 0.00% | $0.0125 | 1.45% | $1.25 | $1.25 | 0.22% |
| Commercial/Industrial Firm A | $0.0000 | 0.00% | $0.0125 | 1.45% | $1.00 | $1.00 | 0.22% |
| Commercial/Industrial Firm B | $0.0000 | 0.00% | $0.0125 | 1.45% | $35.75 | $135.28 | 0.91% |
| Commercial/Industrial Firm C | $0.0000 | 0.00% | $0.0125 | 1.45% | $178.75 | $178.75 | 0.25% |

* Commodity costs held constant
(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).

Department Attachment 7
Docket No. G008/M-19-278
CenterPoint Rate Impacts

| Residential | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | October 2019 PGA | November 2019 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) | $3.2426 | $3.4556 | $2.0567 | $2.0567 | -36.57% | -40.48% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8722 | $1.0907 | 36.61% | 26.87% | 25.05% | $0.2185 |
| Commodity Margin (2) (3) | $2.1477 | $2.1477 | $2.1612 | $2.1612 | 0.63% | 0.63% | 0.00% | $0.0000 |
| Total Cost of Gas | $6.1887 | $6.4630 | $5.0901 | $5.3086 | -14.22% | -17.86% | 4.29% | $0.2185 |
| Average Annual Usage (Dk) | 100 | 100 | 100 | 100 | | | | |
| Average Annual Total Cost of Gas | $618.87 | $646.30 | $509.01 | $530.86 | -14.22% | -17.86% | 4.29% | $21.85 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $21.85 |

| Commercial/Industrial Firm - A | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | October 2019 PGA | November 2019 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) | $3.2426 | $3.4556 | $2.0567 | $2.0567 | -36.57% | -40.48% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8722 | $1.0907 | 36.61% | 26.87% | 25.05% | $0.2185 |
| Commodity Margin | $2.2211 | $2.1649 | $2.1784 | $2.1784 | -1.92% | 0.62% | 0.00% | $0.0000 |
| Total Cost of Gas | $6.2621 | $6.4802 | $5.1073 | $5.3258 | -14.95% | -17.81% | 4.28% | $0.2185 |
| Average Annual Usage (Dk) | 80 | 80 | 80 | 80 | | | | |
| Average Annual Total Cost of Gas | $500.97 | $518.42 | $408.58 | $426.06 | -14.95% | -17.81% | 4.28% | $17.48 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $17.48 |

| Commercial/Industrial Firm - B | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | October 2019 PGA | November 2019 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) | $3.2426 | $3.4556 | $2.0567 | $2.0567 | -36.57% | -40.48% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8722 | $1.0907 | 36.61% | 26.87% | 25.05% | $0.2185 |
| Commodity Margin | $1.8293 | $1.7529 | $1.7664 | $1.7664 | -3.44% | 0.77% | 0.00% | $0.0000 |
| Total Cost of Gas | $5.8703 | $6.0682 | $4.6953 | $4.9138 | -16.29% | -19.02% | 4.65% | $0.2185 |
| Average Annual Usage (Dk) | 2,860 | 2,860 | 2,860 | 2,860 | | | | |
| Average Annual Total Cost of Gas | $16,789.06 | $17,355.05 | $13,428.56 | $14,053.47 | -16.29% | -19.02% | 4.65% | $624.91 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $624.91 |

| Commercial/Industrial Firm - C | Last Rate Case (G008/MR-17-591 & GR-17-285) | Last Demand Change (G008/M-18-462) (Nov 2018) | October 2019 PGA | November 2019 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) | $3.2426 | $3.4556 | $2.0567 | $2.0567 | -36.57% | -40.48% | 0.00% | $0.0000 |
| Demand Cost of Gas (1) | $0.7984 | $0.8597 | $0.8722 | $1.0907 | 36.61% | 26.87% | 25.05% | $0.2185 |
| Commodity Margin | $1.6982 | $1.5795 | $1.5930 | $1.5930 | -6.19% | 0.85% | 0.00% | $0.0000 |
| Total Cost of Gas | $5.7392 | $5.8948 | $4.5219 | $4.7404 | -17.40% | -19.58% | 4.83% | $0.2185 |
| Average Annual Usage (Dk) | 14,300 | 14,300 | 14,300 | 14,300 | | | | |
| Average Annual Total Cost of Gas | $82,070.56 | $84,295.64 | $64,663.17 | $67,787.72 | -17.40% | -19.58% | 4.83% | $3,124.55 |
| Average Annual Total Demand Cost of Gas | | | | | | | | $3,124.55 |

**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 | $0.0000 | 0.00% | $0.2185 | 25.05% | $21.85 | $21.85 | 4.29% |
| Commercial/Industrial Firm A | $0.0000 | 0.00% | $0.2185 | 25.05% | $17.48 | $17.48 | 4.28% |
| Commercial/Industrial Firm B | $0.0000 | 0.00% | $0.2185 | 25.05% | $624.91 | $624.91 | 4.65% |
| Commercial/Industrial Firm C | $0.0000 | 0.00% | $0.2185 | 25.05% | $3,124.55 | $3,124.55 | 4.83% |

* Commodity costs held constant
(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).