April 25, 2019

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

RE: **Review of 2017-2018 Annual Automatic Adjustment Reports**
Docket No. G999/AA-18-374 and Natural Gas Utilities' 2017-2018 Purchased Gas Adjustment - (PGA) True-Up Filings (see attached list)

Dear Mr. Wolf:

Minnesota Rules 7825.2800 through 7825.2830 require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.

Attached please find the Minnesota Commerce Department, Division of Energy Resources' (Department) *Review of the 2017-2018 Annual Automatic Adjustment Reports* (FYE18 AAA Report) for regulated natural gas utilities in Minnesota.

The Department is available should the Minnesota Public Utilities Commission have any questions about the FYE18 AAA Report herein provided.

Sincerely,

/s/ ANGELA BYRNE
Financial Analyst
Division of Energy Resources

AB/ja
Attachments

<u>Docket Numbers for 2017-2018 Gas Utility PGA True-Up Filings:</u>

Docket No. G004/AA-18-567 -	Great Plains Natural Gas Company
Docket No. G022/AA-18-563 -	Greater Minnesota Gas, Inc.
Docket No. G008/AA-18-573 -	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas
Docket No. G011/AA-18-490 -	Minnesota Energy Resource Corporation (MERC) – Consolidated PGA system
Docket No. G011/AA-18-489 -	Minnesota Energy Resource Corporation (MERC) – Northern Natural Gas PGA system
Docket No. G002/AA-18-572 -	Northern States Power Company d/b/a Xcel Energy

REVIEW OF THE 2017-2018

ANNUAL AUTOMATIC ADJUSTMENT REPORTS

SUBMITTED TO THE

MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. G999/AA-18-374

APRIL 25, 2019

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EXECUTIVE SUMMARY – NATURAL GAS UTILITIES

Since 1985, Minnesota Rules 7825.2800 through 7825.2830 have required public utilities that use automatic adjustments to recover energy costs to file annual reports regarding the operation of the automatic adjustments. The reports allow verification of whether utilities are calculating their rate adjustments properly and are implementing these rates in a timely manner. In reviewing the 2017-2018 (FYE18) filings, the Minnesota Commerce Department, Division of Energy Resources (Department) incorporated information from prior years' reports, as well as its assessment of the utilities' monthly automatic adjustment filings submitted throughout the FYE18 reporting period.

The Department's FYE18 Annual Automatic Adjustment natural gas report (FYE18 AAA Report) includes analyses of:

- FYE18 automatic adjustment charge calculations filed pursuant to Minnesota Rule 7825.2810, ANNUAL REPORT; AUTOMATIC ADJUSTMENT CHARGES;

- filings to reconcile or "true up" revenues collected by the utilities to actual gas costs incurred by the utilities, as required by Minnesota Rules 7825.2910 and 7825.2700; and

- supplemental annual reporting requirements ordered by the Minnesota Public Utilities Commission (Commission) in miscellaneous or other dockets during the reporting period.

Recovery of energy costs represents an important factor in the rates customers pay, particularly for ratepayers of natural gas utilities. One part of the rates that customers pay is a true-up reflecting the difference between the actual costs the utilities incur and the actual revenues they recover. True-ups are based on information from the prior year. For example, an over-recovery of costs from a certain customer class in one year would result in an offsetting decrease in the rates (compared to what would otherwise have been charged) assigned to that customer class in the following year. Since customers use different amounts of gas over time, and because some customers leave or join the utility's system over time, there is likely to be some mismatch between the amounts particular customers pay in a given year and the true-up amount assigned to these customers in subsequent years. While it is not administratively feasible to eliminate such mismatches completely, it is essential that utilities attempt to minimize both over- and under-recoveries.

All of the regulated local distribution natural gas utilities provided the information necessary to meet the filing requirements. For this reporting period, these public utilities are:

- Greater Minnesota Gas, Inc. (Greater Minnesota or GMG);
- Great Plains Natural Gas Company (Great Plains);
- Minnesota Energy Resources Corp. (MERC);
- CenterPoint Energy Minnesota Gas, a division of CenterPoint Energy Resources Corp. (CenterPoint Energy or CPE); and
- Northern States Power Company d/b/a Xcel Energy - Gas Utility (Xcel Gas).

In this report, the Department reviews these utilities' compliance with Minnesota Rules 7825.2810 and 7825.2910, which governs the filing of annual automatic adjustment reports, and makes a number of specific recommendations to assure compliance with Commission requirements and to improve the usefulness of future annual automatic adjustment reports. These recommendations are listed in Section IV, *Summary of the Department's Recommendations*.

As noted above, several sections of the report are based on the Commission's requirements and contain information in addition to that specifically required by Minnesota Rules. The Department issued information requests and worked with all of the gas utilities to obtain these data. Based on this information, the Department developed analyses on:

- comparisons of total gas costs incurred and recovered;
- average annual residential customer bills;
- average annual gas costs;
- margins charged to residential customers;
- firm peak-day demand profiles, load factors, and reserve margins;
- penalty charges regarding daily nominations of gas supply;
- revenue from curtailment and balancing penalties;
- peak-day pipeline transportation sources and numbers of suppliers;
- variety of gas suppliers;
- revenues from releasing firm pipeline transportation capacity;
- gas utilities' annual auditor reports;
- lost-and-unaccounted-for gas for each utility;
- report on contractor main strikes and meter testing;
- Minnesota gas utilities' purchasing practices;
- cost of gas storage per unit; and
- Minnesota gas utilities' hedging practices.

The Department appreciates the utilities' cooperation in developing the data for these reports. The FYE18 AAA Report builds on the Department's experience and knowledge gained from prior years' reports and is informed by our continuing assessment of the utilities' automatic adjustment filings throughout the reporting period.

In FYE18, natural gas prices were very slightly higher than prices during FYE17. Despite the colder-than-normal winter discussed further below, prices remained just shy of $3 per Mcf during the entire reporting period, only rising to near $4 per Mcf in January 2018. Several factors seemed to be at play in explaining why prices remained stable. One, while the weather in Minnesota was colder-than-normal, it was only slightly colder than a normal heating season, which would put only typical, seasonal upward pressure on gas prices. Two, storage levels in the months leading up to the 2017-2018 heating season were on par with the 5-year average of approximately 3.8 Bcf,[1] so withdrawals contributed to keeping prices stable. Three, even though consumption rose in the first half of 2018 compared to the

[1] EIA Natural Gas Weekly Update, April 12, 2018, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2018/04_12/.

first half of 2017, production kept relative pace with the increase in consumption. Production from the Marcellus, Utica, and Permian shales accounted for most of the increased production during the reporting period.[2]

The Henry Hub price[3] in 2016-17 ranged between $2.55 and $3.59. In 2017-2018, the Henry Hub price began the reporting period at $2.98 per Mcf in July 2017 and ended the reporting period around $2.97 per Mcf in June 2018, but during the year pricing ranged from the low of $2.67 per Mcf in February 2018 to the high of $3.87 in January 2018.

With the prevalence of shale gas, natural gas production has become more diversified and less reliant on any single basin or area of production. However, there is still a concentration of 51 percent of industry plant capacity in the Gulf of Mexico, making hurricanes an ongoing concern of market interruption.[4] During FYE18, there were two major interruptions from hurricanes, discussed below.

Natural gas storage inventory generally followed the five-year average levels as a result of only slightly colder-than-normal weather and high levels of domestic natural gas production.

Natural gas prices and weather are discussed in further detail below.

The FYE18 AAA Report consists of the following sections:

- an overview with background information (Section I);
- an analysis of the gas utility over-/under-recoveries and true-ups (Section II);
- additional information to assist the Commission (Section III); and
- the Department's concluding comments and recommendations (Section IV).

[2] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2018/06_28/
[3] The Henry Hub is a distribution hub on the natural gas pipeline system that serves as the official delivery location for futures contracts on the New York Mercantile Exchange (NYMEX).
[4] https://www.eia.gov/special/gulf_of_mexico/

I. BACKGROUND AND OVERVIEW

A. OVERVIEW

The Department concludes that all five[5] regulated Minnesota gas utilities met the annual filing requirements, including provision of information relating to fuel procurement and the annual true-up adjustment. As noted above, these utilities are:

- Greater Minnesota;
- Great Plains;
- MERC;
- CenterPoint Energy; and
- Xcel Gas.

The Department concludes that the annual filings are complete as originally filed. The Department's report includes the following sections:

- filing requirements;
- summaries of the gas utilities' 2017-2018 (FYE18) automatic adjustment charge calculations filed pursuant to Minnesota Rule 7825.2810;
- analyses of the gas utilities' true-up filings required by Minnesota Rule 7825.2910, subpart 4;
- supplemental reporting requirements ordered by the Commission in miscellaneous proceedings; and
- reports required by the Commission's previous AAA Report Orders:
  - February 26, 2008 *Order* in Docket No. E,G999/AA-06-1208;
  - December 8, 2008 *Order* in Docket No. E,G999/AA-07-1130;
  - February 12, 2010 *Order* in Docket No. G999/AA-08-1011;
  - April 7, 2011 *Order* in Docket No. G999/AA-09-896;
  - April 3, 2012 *Order* in Docket No. G999/AA-10-885;
  - October 17, 2013 *Order* in Docket No. G999/AA-11-793;
  - November 14, 2013 *Order* in Docket No. G999/AA-12-756 (Docket No. 12-756);

[5] In Docket No. G011,007/GR-10-977, the Commission approved consolidation of MERC's two operating divisions, MERC-PNG and MERC-NMU, into MERC effective January 1, 2013. In that same Order, the Commission approved the consolidation of MERC's four PGA systems into two systems effective July 1, 2013. In Docket No. G011/PA-14-107, the Commission approved a new PGA system (MERC-Albert Lea or MERC AL) related to MERC's purchase of Interstate Power and Light's assets. As of July 1, 2017, per Docket No. G011/GR-15-736, MERC combined its MERC-Albert Lea PGA system with its existing NNG PGA system, leaving two PGA systems: MERC-NNG and MERC-Consolidated.

- August 11, 2014 *Order* in Docket No. G999/AA-13-600;
- August 24, 2015 *Order* in Docket No. G999/AA-14-580;
- February 6, 2017 *Order* in Docket No. G999/AA-15-612;
- June 8, 2018 *Order* in Docket No. G999/AA-16-524; and
- February 27, 2019 *Order* in Docket No. G999/AA-17-493.

B. FILING REQUIREMENTS

Minnesota Rule 7825.2810, subparts 1 and 2 contain the following filing requirements for gas utilities:

<u>Subpart 1</u>

- Paragraph A – Commission-approved base cost of gas;
- Paragraph B – billing amounts in Mcf, Ccf, or Btu for each type of energy cost (*e.g.*, purchased gas, peak shaving, and manufactured gas);
- Paragraph C – billing adjustment amounts;
- Paragraph D – total cost of gas;
- Paragraph E – revenues collected;
- Paragraph F – supplier refunds received; and
- Paragraph G – refunds credited to customers.

<u>Subpart 2</u>

- Paragraph A – a listing of all variances in effect or requested;
- Paragraph B – identification of all changes in demand contracted;
- Paragraph C – the level of customer-owned gas volumes delivered through the utility's system; and
- Paragraph D – a brief explanation of deviations between gas-cost recovery and actual cost.

In addition to reviewing the basic data, the Department investigated and developed additional data to provide more detailed information to assist the Commission in its review of each individual gas utility's annual automatic adjustment report.

C. NATURAL GAS PRICES AND WEATHER

1. Gas Prices in FYE18

As noted above, in FYE18, natural gas prices were only slightly higher than prices during FYE17. Overall, Henry Hub prices remained relatively steady during the reporting period, beginning the reporting period (July 2017) at $2.98 per Mcf and ending at $2.97 per Mcf in June 2018, with the lowest price at $2.67 per Mcf in February 2018 and the highest price at $3.87 in January 2018.

The only significant spike in Henry Hub prices occurred during the first week of January 2018, when prices were above $6.00 per Mcf for two days. The price increased to $5.46 per Mcf on January 16, 2018, but otherwise prices hovered in the $2-$3 range for most of the entire reporting period.[6]

In FYE18, the price of residential propane in Minnesota increased from $13-$18/Mcf in the previous year to approximately $17-$20/Mcf.[7] Volatility of propane prices was lower in FYE18 than FYE17, but the overall price was still high compared to the cost of natural gas.

2. Weather in FYE18

Compared to 30-year normal weather,[8] the weather in the Minnesota area for FYE18 was almost entirely colder than normal. The colder-than-normal annual weather ranged from approximately 1.23 percent colder at the Duluth weather station to approximately 4.44 percent colder in Rochester. Two weather stations recorded overall warmer-than-normal weather; Minneapolis/St. Paul was 0.01 percent warmer and Sioux Falls, SD was 1.78 percent warmer than normal. Natural gas storage inventory generally followed the five-year average levels as a result of only slightly colder-than-normal weather and high levels of domestic natural gas production. Only in January 2018 did storage levels approach inventory lows for the 2013-2017 period.

The heating season (November 2017 through March 2018) was overall colder than normal compared to 30-year normal weather. The colder-than-normal weather ranged from approximately 1.57 percent colder at the Minneapolis/St. Paul weather station to approximately 4.43 percent colder in Rochester. Just like on an annual basis, two weather stations recorded warmer-than-normal conditions; Sioux Falls, SD was 0.49 percent warmer and Fargo, ND was 5.93 percent warmer than normal.

According to Northern Natural Gas Company's (NNG) March 2018 *Northern Notes*, the 2017-2018 heating season (November through March) was colder than normal during all five winter months. The 2017-2018 heating season was eight percent colder than normal. The colder-than-average heating season occurred after a mixture of warmer-than-average and colder-than-average heating seasons in the previous five years.

[6] https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm
[7] http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPLLPA_PRS_SMN_DPG&f=W. One gallon of propane equals approximately 0.915 therms.
[8] Based on weather data from 1981 through 2010.

NNG experienced its top two market area[9] peak delivery days in December 2017. The previous highest recorded market area peak delivery was January 18, 2016, which averaged 5.158 Bcf. On December 26, 2017, the market area delivery averaged 5.221 Bcf. On December 27, 2017, the market area delivery averaged 5.164 Bcf. On December 31, 2017, the market area delivery averaged 5.020 Bcf and on January 1, 2018, market area deliveries averaged 5.067 Bcf, making this the first time Northern has recorded deliveries of four 5.0 Bcf days in a heating season.

NNG experienced 35 days of market area deliveries of 4.0 Bcf/day or greater during the 2017-2018 heating season. This amount compares to 20 days of market area deliveries in excess of 4.0 Bcf/day in 2016-2017 and 13 days of market area deliveries in excess of 4.0 Bcf/day in the 2015-2016 heating season.

During FYE18, there were two major interruptions in natural gas production from hurricanes. The first was in August 2017 from Hurricane Harvey, a category four storm, and the first significant disruption to natural gas production since Hurricane Isaac in 2012. In the 13 days following Harvey, the cumulative production effect was the loss of 6.6 Bcf of natural gas, or seven percent of the Gulf of Mexico's total August production.[10]

The second interruption of production came in October 2017 from Hurricane Nate, a category one storm. Although significantly weaker than Harvey, Nate passed through the highest producing area in the Gulf of Mexico and caused nearly double the disruption to production. Cumulatively, 11.8 Bcf, or 15 percent, of total October Gulf of Mexico natural gas production was lost due to this storm.[11]

Despite the disruptions in production, price volatility remained very low following each of the storms.[12] Prices remained relatively stable, rising only by $0.10 to $0.20 per Mcf in the months following each of the storms. The Department notes that the low price volatility was likely driven by the fact that the production disruptions were minor compared to domestic production levels. During FYE18, domestic natural gas production levels were approximately 80 Bcf/day.[13]

[9] NNG's market area refers to NNG's service territory north of Demarcation, KS.
[10] https://www.eia.gov/todayinenergy/detail.php?id=37212
[11] *Id.*
[12] https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm
[13] https://www.eia.gov/naturalgas/weekly/#tabs-supply-1. April 11, 2019 release.

D. GAS UTILITIES SUMMARY

The Department reviewed the gas utilities' filings to:

- identify systematic patterns of over- or under-recoveries that may be occurring over time;
- identify any incorrect calculations of annual true-up adjustment factors;
- identify additional issues that may warrant Commission attention; and
- assess the utilities' compliance with additional annual automatic adjustment report filing requirements, as ordered by the Commission in miscellaneous proceedings.

As discussed further in Section II, the Department categorized each gas utility's estimated revenue recovery by pipeline system and customer class to allow for full verification of the actual annual fuel costs and the related annual true-up adjustments. The Department reviewed the reasonableness of the utilities' explanations of differences between actual gas costs and gas-cost recovery based on estimated gas costs, as required in Minnesota Rule 7825.2810, subpart 2, paragraph D. Further, since Minnesota Rule 7825.2910 requires that gas utilities "true up" all over- or under-recoveries of gas costs, the Department also verified the accuracy of each utility's annual true-up adjustments.

Gas-cost recovery generally represents the largest component in the rates and bills that customers pay. Further, as noted above, there can be mismatches in the over- or under-charges in a given year and the true-up amounts in the subsequent year. These mismatches affect rates in subsequent years such that an over-recovery for a certain customer class in one year results in an offsetting decrease in the rates (compared to what would otherwise have been charged) assigned to that customer class in the following year. Likewise, an under-recovery in one year increases rates in the subsequent year, compared to rates that would otherwise have been charged. Thus, it is essential that utilities attempt to minimize both over- and under-recoveries.[14] Section II below provides analyses of the true-ups for individual utilities. Table G1 below summarizes the fuel-cost recovery during the FYE18 reporting period for gas utilities.

[14] As discussed further in the individual gas utility evaluations, Section II, CenterPoint Energy and Xcel Gas have received Commission approval to add a monthly demand adjustment to their demand cost recovery rate in order to match costs better within the true-up year.

Table G1:[15] Summary of Gas Utilities' Annual Demand & Commodity Cost Recovery[16]

July 1, 2017 - June 30, 2018

Utility/System	Gas Cost Recovered ($)	Incurred Cost of Gas ($)	Over(Under) Recovery ($)	Over(Under) Recovery (%)
Greater Minnesota	$5,416,510	$5,565,282	$(148,772)	(2.67%)
Great Plains	$15,195,404	$16,897,064	$(1,701,660)	(10.07%)
MERC				
CON	$19,570,169	$20,787,490	$(1,217,321)	(5.86%)
NNG[17]	$125,683,269	$132,619,114	$(6,935,845)	(5.23%)
CenterPoint Energy	$526,387,508	$572,097,914	$ (45,710,406)	(7.99%)
Xcel Gas	$270,563,892	$274,859,908	$(4,296,016)	(1.56%)
MN TOTAL	**$962,816,752**	**$1,022,826,772**	**$(60,010,020)**	**(5.87%)**

As shown above, all of the six PGA systems[18] under-recovered gas costs (demand and commodity), ranging from negative 1.56 percent for Xcel Gas to negative 10.07 percent for Great Plains. The weighted average for all Minnesota gas utilities was an under-recovery of 5.87 percent.[19] The Minnesota total cost of gas for FYE18 was $1,022,826,772 and for FYE17 was $862,350,817, which represents an increase in gas costs of $160,475,955, or approximately 19 percent from the level in FYE17. Table G1a below presents a comparison of FYE18 gas costs to the nominal gas costs in past reporting periods.

[15] The information for Table G1 can be found in each of the utilities' true-ups, which have been included as Department Attachments G5 through G11.
[16] The recovery in Table G1 includes credits or revenues related to gas costs.
[17] MERC purchased Interstate Power & Light's gas utility serving Minnesota on April 30, 2015, creating the Albert Lea PGA system. In Docket No. G011/GR-15-736, MERC merged the Albert Lea PGA system with its NNG system effective July 1, 2017.
[18] The Department notes that "gas utility" and "PGA system" are, at times, interchangeable in this Report.
[19] The Minnesota weighted-average amount is calculated by dividing the total under-recovery amount by the total cost of gas.

Table G1a: Summary of Gas Utilities' Annual Fuel Cost Recovery

Report Period	Total Cost of Gas	FYE18 Increase/ (Decrease) Compared to Prior Years
FYE18	$1,022,826,772	
FYE17	$862,350,817	19%
FYE16	$730,948,119	40%
FYE15	$1,140,929,250	(10)%
FYE14	$1,659,257,488	(38%)
FYE13	$1,063,629,628	(4%)
FYE12	$899,685,483	14%
FYE11	$1,228,496,903	(17%)
FYE10	$1,290,861,146	(21%)
FYE09	$1,667,839,793	(39%)

Table G1a indicates that the total cost of gas including demand and commodity costs for FYE18 was nearer the average of total gas costs in the previous ten years.

Table G2 below summarizes the over- and under-recoveries for each utility over the past ten years, including a ten-year non-weighted average, and the cumulative balance percentage over- or under-recovery.

Table G2: Percent Over-Recovery/(Under-Recovery)

FYE09-FYE18[20]

Utility/System	Greater Minnesota	Great Plains North	Great Plains South	Great Plains - CON[21]	MERC CON	MERC NNG	MERC AL[22]	CenterPoint Energy	Xcel Gas
2008-2009	(4.96)	(0.36)	(3.34)		3.85	1.21		1.17	(0.23)
2009-2010	(5.18)	(3.57)	(2.62)		(2.09)	(1.25)		(3.96)	(1.26)
2010-2011	(3.92)	0.45	(1.95)		2.00	2.58		(0.66)	(0.50)
2011-2012	0.58	(7.83)	(4.73)		(2.15)	(6.19)		(4.68)	(3.15)
2012-2013	1.46	(3.66)	(1.86)		2.82	0.08		(0.84)	(0.36)
2013-2014	(0.27)	(12.09)	(13.57)		(9.25)	(6.45)		(6.88)	(10.47)
2014-2015	0.98	1.57	(3.00)		(3.91)	1.90	(27.03)	1.19	(2.24)
2015-2016	1.32	(1.66)	(2.48)		0.72	(2.60)	(3.47)	(2.81)	(2.34)
2016-2017	(0.91)	(1.00)	(4.48)		1.41	(2.97)	(4.45)	(3.97)	(1.72)
2017-2018	(2.67)			(10.07)	(5.86)	(5.23)		(7.97)	(1.56)
Average	**(1.36)**	**(2.82)**	**(3.80)**	**(10.07)**	**(1.25)**	**(1.89)**	**(8.74)**	**(2.86)**	**(2.38)**
Cumulative[23]	**(2.66)**	**0.00**	**0.00**	**(10.05)**	**(6.00)**	**(4.99)**	**0.00**	**(7.62)**	**(0.09)**

As shown in Table G2, all of the PGA systems experienced cumulative under-recoveries during FYE18.

The ten-year average from FYE09 through FYE18 shows an under-recovery for all of the gas utilities. The Department's analysis of the over- or under-recovery for each utility is presented below in Section II.

[20] See Department Attachment G2 graph comparing historical true-up adjustments.
[21] In Docket No. G004/GR-15-879, Great Plains consolidated its North and South PGA systems into one Consolidated PGA system, effective July 1, 2017.
[22] Effective July 1, 2017, MERC merged its Albert Lea PGA system with its NNG PGA system per Docket No. G011/GR-15-736. MERC purchased Interstate Power & Light's gas utility serving Minnesota on April 30, 2015. In Table G2 for 2014-2015, MERC-AL includes two months of data.
[23] The figures for this row are included in Department Attachment G5 through G11 in each of the utility's true-ups. The cumulative over- or under-recovery is a calculation based on prior years' true-ups and the present year's true-up.

Table G3 below provides a summary of the current period's over- or under-recoveries. This table illustrates over- or under-recoveries for firm and interruptible classes as a whole and by pipeline system for equivalent PGA systems during the FYE18 true-up period.

Table G3: Percent Over-Recovery/(Under-Recovery)
FYE18 by Firm and Interruptible Classes

Utility/System	Firm	Interruptible[24]	Total
Greater Minnesota	(2.73)%	(2.39)%	(2.67)%
Great Plains	(9.73)%	(11.33)%	(10.07)%
MERC			
CON	(5.12)%	(11.96)%	(5.86)%
NNG	(4.70)%	(10.76)%	(5.23)%
CenterPoint Energy	(8.15)%	(6.50)%	(7.99)%
Xcel Gas	(0.57)%	(8.55)%	(1.56)%
MN Weighted Avg.	**(5.63)%**	**(7.84)%**	**(5.87)%**

Table G3 shows that all of the PGA systems experienced an under-recovery, and four of the six systems experienced an under-recovery in excess of five percent.[25]

The following two sections include the Department's detailed analysis of the significant factors causing the under-recoveries reported in the above tables, as well as summaries of each utility's annual fuel reports, utility-specific reporting requirements, and other items the Department notes for the Commission.

[24] MERC's interruptible figures include the Joint customers' firm requirements since the Joint customers are not considered firm on the peak day.
[25] The Department specifies the five percent threshold per Minnesota Rule 7825.2920, subpart 2, concerning adjustment errors.

E. IMPACTS ON GAS COSTS AND THE RECOVERY OF GAS COSTS

It is normal for utilities to over- or under-recover gas costs. Factors that commonly lead to gas cost over- or under-recovery include:

- weather varying from “normal” weather;
- calculation of the volumetric demand-cost recovery rate;
- capacity release credits;
- deviations between forecasted and actual sales volumes and prices;
- prorating of customer bills; and
- the “three-cent rule” from Minnesota Rule 7825.2700, subp. 3.

Each of these factors is discussed below.

1. **Weather Variance** – Weather is typically the largest factor affecting firm natural gas sales volumes. Therefore, changes in weather can significantly affect the recovery of both demand and commodity gas costs.[26]

   There are seven area weather stations used for Minnesota data.[27] The Department compiled weather data from each of those stations as summarized below and in more detail in Attachment G1. Compared to 30-year normal weather from 1981 to 2010,[28] the weather in Minnesota for FYE18 as a whole was generally colder than normal across the state. The only weather station that recorded warmer-than-normal temperatures was Sioux Falls, SD by 1.78 percent. The Minneapolis/St. Paul station reported normal weather for FYE18, at only 0.01 percent warmer than normal. For the reporting period, the colder-than-normal weather ranged from approximately 1.23 percent colder at the Duluth station to approximately 4.44 percent colder in Rochester. The FYE18 weather in Minnesota was as follows:

[26] Demand gas costs represent the cost of pipeline capacity to transport firm gas supplies. Commodity gas costs represent the cost of the physical natural gas product.

[27] Of the seven National Weather Service stations in our area, five are located in Minnesota (Minneapolis/St. Paul, Rochester, Duluth, International Falls, and St. Cloud), one is located in Fargo, North Dakota (representing Moorhead and other parts of northwestern Minnesota), and one is located in Sioux Falls, South Dakota (representing southwestern Minnesota).

[28] Comparing the reported weather to “normal” weather varies depending on whether a utility uses a thirty-year (1981-2010) average from the National Oceanic and Atmospheric Administration (NOAA) for normal weather data calculations or some other basis to estimate normal weather data calculations.

Table G4
FYE18 Weather in Minnesota

Weather Station	Change from normal*
Duluth	1.23%
International Falls	2.28%
Fargo, ND	1.25%
St. Cloud	1.82%
Minneapolis/St. Paul	(0.01)%
Rochester	4.44%
Sioux Falls, SD	(1.78)%

** Negative indicates warmer than normal (fewer heating degree days)*

The weather in Minnesota for the heating season November to March was also colder than normal compared to 30-year normal weather for all but two weather stations; Fargo, ND and Sioux Falls, SD. The colder-than-normal weather ranged from approximately 1.57 percent colder at the Minneapolis/St .Paul weather station to approximately 4.43 percent colder in Rochester as follows:

Table G5
2017-2018 Winter Weather in Minnesota

Weather Station	Change from normal
Duluth	4.17%
International Falls	4.39%
Fargo, ND	(5.93)%
St. Cloud	3.00%
Minneapolis/St. Paul	1.57%
Rochester	4.43%
Sioux Falls, SD	(0.49)%

Recovery of demand costs is affected by weather because the demand portion of utilities' rates is calculated based on test-year or historical weather-normalized firm sales, but is recovered on each unit of firm gas actually sold. Thus, when weather is warmer than normal, utilities may not recover all incurred demand costs due to lower customer use of natural gas. Conversely, utilities may recover more demand costs than they incurred when customers use more gas during the colder-than-normal periods.

Due to the colder-than-normal weather experienced during the winter, all things being equal, demand costs should have been over-recovered (interruptible customers are not charged for demand costs). During FYE18, all of the PGA systems over-recovered demand costs except CenterPoint Energy, ranging from an under-recovery of 2.67 percent for CenterPoint Energy to an over-recovery of 42.01 percent for MERC-

Consolidated. Each PGA system over/(under) recovered its demand costs by the percentages shown below.

Table G6
FYE18 Over-/(Under)-Recovery of Demand Costs as Filed[29]

Greater Minnesota	1.55%
Great Plains-Consolidated	4.27%
MERC-Consolidated	42.01%
MERC-NNG	15.71%
CenterPoint Energy	(2.67)%
Xcel Gas	8.76%

In the individual utility true-up evaluations contained in Section II, the effect of weather and other reasons for over- and under-recoveries of demand costs are discussed in more detail.

Each PGA system over/(under) recovered its commodity costs by the percentages shown below.

Table G7
FYE18 Over-/(Under)-Recovery of Commodity Costs as Filed[30]

Greater Minnesota	(3.51)%
Great Plains-Consolidated	(13.70)%
MERC-Consolidated	(13.37)%
MERC-NNG	(9.23)%
CenterPoint Energy	(9.22)%
Xcel Gas	(3.72)%

Recovery of commodity costs is also affected by weather, as well as price fluctuations. The gas-commodity portion of rates is generally based on price estimates made during the week prior to the beginning of each month. Thus, an unexpected cold period during the middle of a month, following normal weather in the last week in the preceding month, generally will lead to an under-recovery of higher-than-expected gas commodity costs. Conversely, a cold period during the last week of the month followed by normal weather generally leads to an over-recovery of commodity costs if actual commodity gas

[29] The percentages include revenue such as capacity release and curtailment penalty revenue. Capacity release and curtailment penalty revenue decrease the under-recovery percentages, and increase the over-recovery percentages.
[30] Except for CenterPoint Energy, the percentages include revenue such as balancing penalty revenue. Additionally, commodity costs include storage and balancing costs.

costs correspondingly decline. Similarly, a prolonged period of either warmer-than-normal or colder-than-normal weather at the beginning of the winter heating season can impact natural gas prices during the remainder of the heating season.

Many inversely-related factors affected commodity costs in FYE18. As discussed above in Section I.C., weather for the fiscal year and the heating season in FYE18 was colder than FYE17, which put slight upward pressure on commodity prices. Demand for natural gas is increasing, which would also put upward pressure on commodity prices. However, assuming no capacity restraints, current production is capable of keeping up with rising demand. Having flexibility in production to better match current demand has kept prices relatively stable for the last several years. In addition, with weather extremes becoming more prevalent, predicting seasonal commodity prices has become more difficult. That said, commodity prices under $4.00 per Mcf are all-around beneficial to ratepayers, regardless of whether the specific prices follow previous seasonal conventions.

2. **Calculation of the monthly volumetric demand-cost recovery rate**

Changes in demand costs – In general, demand costs are the costs of reserving pipeline capacity to transport firm gas supplies.[31] Pursuant to Minnesota Rules 7825.2910, subpart 2, gas utilities file a petition 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. The petition must include a description of the factors contributing to the need for changing demand and the utility's design-day demand by customer class and the change in design-day demand.

Test-Year Sales Volumes – Since the current non-gas base rate for most utilities' customers generally does not include a separate demand charge, demand costs are recovered through a volumetric rate on all firm sales through the PGA. This volumetric demand-cost recovery rate is computed by dividing contracted annual demand costs by either the test-year demand volume from a utility's most recent general rate case (which, pursuant to Minnesota Rule 7825.2700, subpart 5, must be used for three years following a utility's rate case) or annual demand volume. Minnesota Rules define the annual demand volume as the actual volume of gas sold during the most recent 12 months (historical), adjusted by an average percentage change in sales computed over the preceding three-year period and normalized for weather.

[31] Department Attachment G3 provides a glossary of pipeline demand services and other relevant terminology. Department Attachment G4 provides a chart, by utility, detailing whether pipeline services and other fees are recovered in the demand or commodity portion of the PGA.

The demand-cost recovery rate is calculated in the monthly PGA by applying FERC-approved natural gas pipeline rates[32] to the Commission's approved demand entitlement level of the utility. Demand entitlements are normally contracted for with the natural gas pipeline on an annual basis with the new levels of demand effective November 1. When demand costs change, application of the monthly PGA demand rate may not result in recovery of one-twelfth of the annual demand costs.[33]

Further, sales are generally much greater during winter than during summer months. If the recovery of annual demand costs during the winter months is lower due to warmer-than-normal weather during the heating season, there generally will be an under-recovery of demand costs that year, all else being equal.[34] This under-recovery occurs because the winter months are when the greatest percentage of cost recovery generally occurs.

3. **Capacity Release Credits** – A utility may sell its contracted pipeline capacity ("capacity-release transaction") if the utility determines that a portion of reserved capacity will not be needed to serve its customers. The Commission requires utilities to return to firm ratepayers all revenue from these capacity-release transactions. The monthly PGA and/or the annual true-up amount are credited, thereby reducing the demand costs needed to be recovered. For those utilities that credit the annual true up amount rather than the monthly PGA, this credit will result in an over-recovery of demand costs on a monthly basis, all else being equal.

4. **Deviations between forecasted and actual sales volumes and prices** – For commodity costs, a common cause of over- or under-recovery is the deviation between monthly forecasts and actual sales volumes and changes in commodity prices. Market conditions will affect the price of natural gas. For regulatory purposes, natural gas commodity costs are usually a pass-through cost for utilities via PGAs.

5. **Prorating of customer bills** – When a utility reads a customer's meter in the middle of the month, the registered usage represents consumption from two different PGA (calendar month) periods. Thus, the utility must bill the customer based on an estimate of the consumption that took place during each PGA period. Because this prorated bill

[32] If the natural gas pipeline is intrastate then the Commission-approved rates apply.
[33] Examples of changes that affect the utility's demand costs include changes in the:

- entitlement level;
- assignment of demand to commodity cost;
- allocation of costs between jurisdictions; and
- natural gas pipeline rates approved by FERC.

[34] Likewise, if there is higher demand during the winter months due to colder-than-normal weather, there generally will be an over-recovery of demand costs that year, all else being equal.

will not exactly match the true consumption that took place each month, except by coincidence, over- or under-recoveries typically will result.

6. **The three-cent rule** – Minnesota Rule 7825.2700, subpart 3, specifies that utilities do not need to file monthly PGAs if the change during the month is less than $0.03 per 1,000,000 BTUs (approximately 1 Mcf). This allowance, if exercised by a utility, would cause an over- or under-recovery of gas costs for that month.

To some extent, all of the above-listed factors may affect gas costs and recovery of gas costs for all of Minnesota's gas utilities. The following individual gas utility true-up section highlights the items from this list and any particular causes not included in the list that caused notable over- and under-recoveries for each individual gas utility.

II. REVIEW OF OVER-/UNDER-RECOVERIES AND TRUE-UPS

As discussed above, based on the winter weather being overall colder than normal and all else being equal, the Department would expect the PGA systems to over-recover demand and commodity costs. All of the PGA systems except for CenterPoint Energy over-recovered demand costs from firm customers. However, all of the PGA systems under-recovered commodity costs.

The Department discusses the recovery of gas costs and true-up calculations of each utility's AAA report and true-up filings, along with any general concerns.

A. GREATER MINNESOTA GAS, INC.

1. Recovery of Gas Costs and True-up Calculations

On August 30, 2018, Greater Minnesota submitted its 2018 Annual True-up Report in G022/AA-18-563. GMG included in its reports the information required by Minnesota Rule 7825.2810. The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE18 reporting period, GMG reported that it under-recovered its total gas costs by $148,772, or approximately 2.67 percent, for a cumulative under-recovery of 2.66 percent.[35] By customer class, Greater Minnesota reported under-recoveries for the current reporting period as follows:

[35] The figure of 2.66 percent represents the cumulative under-recovery of $147,948, which is the basis for GMG's FYE18 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Greater Minnesota's true-up filing, Docket No. G022/AA-18-563.

Table G8 – Greater Minnesota Gas
FYE18 Percent Over-Recovery/ (Under-Recovery) by Customer Class[36]
(As filed by Greater Minnesota)

Firm	(2.73)
Agricultural - Interruptible	(3.80)
General – Interruptible	(0.47)
Total System	(2.67)

Using the sales volumes forecasted by Greater Minnesota for the FYE19[37] period results in the true-up factors by customer class as shown below.

Table G8a – Greater Minnesota Gas
True-Up Factors per Mcf by Customer Class
(As filed by Greater Minnesota)

Firm	$0.1076
Agricultural - Interruptible	$0.1976
General - Interruptible	$0.0256

The Department's analysis of Greater Minnesota's true-up calculation indicates that the current year's deviation between gas-cost recoveries and actual gas costs was primarily due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Greater Minnesota over-recovered its current demand costs by $14,314, or approximately 1.55 percent. The demand-cost over-recovery includes capacity-release revenue of $38,504. Without this revenue, there was an under-recovery of demand costs of $24,189 or approximately 2.62 percent. In its *2018 Annual Automatic Adjustment Report*, GMG stated,[38]

   > To the extent estimated volumes and prices vary from actual purchases, a monthly over- or under-recovery will occur.

   Weather across the state of Minnesota was between 1.78 warmer than normal to 4.44 percent colder than normal; specifically, 1.82 percent colder in the St. Cloud area and 0.01 percent warmer than normal in the Minneapolis/St. Paul area.

[36] A supporting spreadsheet with detailed calculations is contained in Department Attachment G5.
[37] GMG's true-up filing, Attachment A.
[38] GMG's *Annual Automatic Adjustment Report,* page 4.

Based on this information, the Department concludes that Greater Minnesota's over-recovery of demand costs appears to be reasonable.

2. Commodity Costs – Greater Minnesota under-recovered its current commodity costs by $163,086, or approximately 3.51 percent. GMG stated that the commodity recovery rate component is based on estimated purchases prior to the beginning of the month. To the extent estimated volumes and prices vary from actual purchases, a monthly over- or under-recovery will occur.[39]

   The Department concludes that GMG's under-recovery of commodity costs appears to be reasonable.

Based on its review, the Department recommends that the Commission accept GMG's FYE18 true-up.

2. Compliance and/or Supplemental Reporting Requirements

<u>Docket No. G022/M-11-804.</u> In this Docket, the Commission's December 22, 2011 *Order Authorizing New Retail Service* required GMG to provide, each year in its annual AAA report, for each relevant GMG rate class and for each upstream rate schedule used for purchase for resale service (i.e. for each group of purchase for resale customer) the:

- number of upstream local distribution company (LDC) meters,
- number of retail GMG customers, and
- volume of gas sold to each group of purchase for resale customer.

GMG's New Retail Service is intended to allow more customers to have access to natural gas service. The service is available to customers who do not qualify for new service under another gas utility's main extension tariff, but are willing to pay for GMG's costs of providing natural gas service to them.

The Commission required GMG to provide the information as recommended by Commission Staff in briefing papers:

> The Department recommended the Commission require GMG to show in the Company's next rate case that the rates charged for the purchase for resale service cover the cost of adding these new customers to GMG's system. GMG agreed and proposed that it track the capital expenditures and customer load additions provided under this tariff for review in the Company's next general

[39] GMG's *Annual Automatic Adjustment Report,* page 4.

> rate proceeding. Staff agrees this is good idea and believes the additional service extension request information recommended earlier in the briefing papers would help GMG demonstrate this point.
>
> Staff also believes a relatively simple additional annual reporting requirement would allow for some basic monitoring of this service and would be helpful. In addition to requiring GMG to provide a reference in its monthly purchased gas adjustment reports to each of the upstream LDC rate schedules that GMG charges purchase for resale customers, staff recommends that in GMG's annual September 1 automatic adjustment of charges reports, the Company provide for each relevant GMG rate class and for each upstream rate schedule used for the purchase for resale service: (1) the number of upstream LDC meters, (2) the number of retail GMG customers, and (3) the volume of gas sold to each group of customers.

GMG provided the required information in its filing; the number of customers served increased slightly from the previous year.[40] The Department concludes that GMG is in compliance with the filing requirements in Docket No. G022/M-11-804.

<u>Docket No. G999/AA-14-580 and G999/AA-17-493.</u> The Commission's August 24, 2015 *Order* in Docket 14-580 required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. In its February 27, 2019 *Order* in Docket 17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20. On page 5 of its AAA Report, GMG stated that it "did not have any non-compliant interruptible customers that engaged in unauthorized use during a curtailment period; hence GMG has nothing to report." The Department concludes that GMG complied with the reporting requirements in Docket 17-493.

3. Summary and Recommendations

The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

[40] GMG's *Annual Automatic Adjustment Report,* page 5.

- accept GMG's FYE18 true-up, Docket No. G001/AA-18-563; and
- allow GMG to implement its true-up, as shown in Department Attachment G5 of the FYE18 AAA Report.

B. GREAT PLAINS NATURAL GAS COMPANY

1. Recovery of Gas Costs and True-Up Calculations

On August 31, 2018, Great Plains submitted its 2018 Annual True-Up Report in Docket No. G004/AA-18-567 in compliance with Minnesota Rule 7825.2810. The Department concludes that Great Plains' report is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE18 reporting period, Great Plains under-recovered its total gas costs by $1,701,660, or approximately 10.07 percent, for a cumulative under-recovery of total gas costs of approximately 10.05 percent.[41] Great Plains' under-recoveries by customer class for the current reporting period are shown below.[42]

Table G9 – Great Plains
FYE18 Percent Over-Recovery/ (Under-Recovery) by Customer Class[43]
(As filed by Great Plains)

Firm	(9.73)
Interruptible	(11.33)
Total System	(10.07)

Using the sales volumes forecasted by Great Plains for the FYE19 period results in the following true-up factors by district and by customer class:

[41] The figure of 10.05 percent represents the cumulative under-recovery of $1,698,948, which is the basis for the August 31, 2018 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Great Plains' true-up filing, Docket No. G004/AA-18-567.
[42] Beginning July 1, 2017, Great Plains consolidated its North and South PGA systems into one consolidated PGA system. The term "North District" referred to the five Minnesota communities served by Great Plains via Viking Gas Transmission Company's (Viking) pipeline. These communities are: Fergus Falls, Pelican Rapids, Breckenridge, Crookston, and Vergas. The term "South District" referred to the thirteen Minnesota communities served by Great Plains via Northern's pipeline. These communities are: Belview, Boyd, Clarkfield, Danube, Dawson, Echo, Granite Falls, Marshall, Montevideo, Redwood Falls, Renville, Sacred Heart and Wood Lake.
[43] A supporting spreadsheet with detailed calculations is contained in Department Attachment G6.

Table G9a – Great Plains
True-Up Factors per Mcf by Customer Class
(As filed by Great Plains)

Class	Consolidated System
Firm	$0.4859
Interruptible	$0.4649

The Department's analysis of Great Plains' true-up calculation indicates that the current year's deviation between gas-cost recoveries and actual gas costs was primarily due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Great Plains over-recovered its demand costs by $145,827, or approximately 4.27 percent, during the reporting period. The demand-cost over-recovery includes capacity release revenue of $0. Great Plains stated that the over-recovery of demand costs was due to the following reasons: [44]

   - Weather was only 0.21 percent colder than normal for the twelve months ending June 30, 2018. The colder than normal months of April and May contributed to the over-recovery; and

   - Great Plains recovers demand costs on a volumetric basis, while costs are assessed on a fixed monthly basis. Generally, demand costs are under-recovered during the summer months, when firm sales volumes are low and over-recovered during the winter months when sales volumes are high.

   As shown in Section I.E. above, the nearest weather station to Great Plains' northern service area, Fargo, was 1.25 percent colder overall and 5.93 percent warmer during the November-March heating season. The nearest weather station to Great Plains' southern service area, Sioux Falls, was 1.78 percent colder overall, but during the heating season was 0.49 percent warmer. Great Plains' customers experienced a mix of colder- and warmer-than-normal weather. A significant departure from normal temperatures in low-use or shoulder months, like April and May, will skew recovery of demand costs. Based on this information, the Department concludes that Great Plains' current 4.27 percent over-recovery of demand costs appears to be reasonable.

[44] Great Plains' *Annual Automatic Adjustment Report,* page 4.

2. Commodity Costs – Great Plains under-recovered its commodity costs (including penalty revenue of $71,725[45]) by $1,847,487, or approximately 13.70 percent. Excluding the penalty revenue, the under-recovery of commodity was $1,919,212, or approximately 14.23 percent. Great Plains stated that the under-recovery was partly a result of timing differences between the cost of gas recovered in the rates and the actual gas costs. Great Plains also stated,[46]

> Approximately $1.4 million of the under-recovered commodity costs occurred in January business[,] the result of the daily gas price at the Northern Natural Ventura trading hub settling around $67 per dk for gas days 12/29/27 through 12/31/17. The price of gas during the trading day at one time exceeded $100 per dk in an extremely volatile market. The price spike was primarily the result of increased demand from forecasted colder than normal temperatures, anticipated supply constraints due to production freeze-offs and a critical day notice from NNG.

The Department appreciates the additional information about high daily prices in late December. As discussed in Section I.C. above, the average Henry Hub price spiked during the first week of January, lining up with Great Plains' experience. For this reason, despite the large percentage under-recovery, the Department concludes that Great Plains' under-recovery of commodity costs appears to be reasonable.

Based on its review, the Department recommends that the Commission accept Great Plains' FYE18 true-up.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G999/AA-14-580 and G999/AA-17-493. As noted above, the Commission's August 24, 2015 *Order* in Docket 14-580 required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. In its February 27, 2019 *Order* in Docket 17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

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[45] Great Plains' response to Department Information Request No. 9. Responses are available upon request.
[46] Great Plains' *Annual Automatic Adjustment Report,* page 4.

In its reply to Department Information Request No. 8 in Docket 18-374, Great Plains reported that it did not have any non-compliant gas usage in FYE18 and that no changes occurred in how it handles curtailment penalty revenue. The Department reminds Great Plains to include this compliance information in its AAA Report as well, but otherwise concludes that Great Plains complied with the reporting requirements in Docket No. 17-493.

3. Summary and Recommendations

The Department concludes that Great Plains' FYE18 annual automatic adjustment report is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept Great Plains' FYE18 true-ups, Docket No. G004/AA-18-567; and
- allow Great Plains to implement its true-ups, as shown in Department Attachment G6 of the FYE18 AAA Report.

C. MINNESOTA ENERGY RESOURCES CORPORATION (MERC)

In its December 8, 2014 *Order Approving Sale Subject to Conditions*, the Commission approved MERC's acquisition of Interstate Power & Light's gas utility serving Minnesota in Docket No. G001,G011/PA-14-107. Ordering Paragraph 4 required MERC to continue to maintain the Interstate Gas PGA for transitioned Interstate Gas ratepayers until MERC's next general rate case and, at that time, reconcile the two fuel supply systems into one. The sale closed on April 30, 2015.

On September 30, 2015, MERC filed a general rate case in Docket No. G011/GR-15-736. In its Initial Filing, MERC proposed to combine its MERC-NNG and MERC-Albert Lea PGA systems beginning July 1, 2017, following the implementation of final rates. In her Order, the Administrative Law Judge (ALJ) in that case found MERC's proposed timeline to be reasonable.[47] In its October 31, 2016 *Findings of Fact, Conclusions, and Order,* the Commission approved the ALJ's findings.[48] FYE18 is the first full year of data for the combined MERC-NNG and MERC-Consolidated PGA systems.

1. Recovery of Gas Costs and True-Up Calculations

On August 31, 2018, MERC-NNG submitted its 2018 Annual True-Up Report in Docket No. G011/AA-18-489 in compliance with Minnesota Rule 7825.2810. The Department concludes

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[47] *Findings of Fact, Conclusions of Law, and Recommendation*, issued August 19, 2016, Findings 752-758, pages 143-144.
[48] *Findings of Fact, Conclusions, and Order*, issued October 31, 2016, Ordering Paragraph 2, page 54.

that MERC-NNG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE18 reporting period, MERC-NNG under-recovered its total gas costs by $6,935,845, or approximately 5.23 percent, for a cumulative under-recovery of total gas costs of approximately 4.99 percent.[49]

On August 31, 2018, MERC-Consolidated or MERC-CON submitted its 2018 Annual True-Up Report in Docket No. G011/AA-18-490 in compliance with Minnesota Rule 7825.2810. The Department concludes that MERC-CON's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

The PGA system for MERC-CON under-recovered total gas cost by $1,217,321, or approximately 5.86 percent, for a cumulative under-recovery of 6.00 percent.[50]

The Department's analysis indicates that, by customer class and system, MERC's under-recoveries during the current reporting period were as follows:

Table G10 - MERC
FYE18 Percent Over-Recovery/(Under-Recovery) by System and Class[51]
(As filed by MERC)

Class[52]	NNG	Consolidated
GS	(4.70)	(5.12)
SVJ/LVJ/SLVJ Demand	0.00	0.00
SVI/SVJ/LVI/LVJ/SLVI Commodity	(10.79)	(12.12)
Total System	(5.23)	(5.86)

Using the sales volumes forecasted by MERC for the FYE19 period results in the following true-up factors by system and class:

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[49] The figure of 4.99 percent represents the cumulative under-recovery of $6,622,503, which is the basis for the FYE19 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-NNG's true-up filing, Docket No. G011/AA-18-489.

[50] The figure of 6.00 percent represents the cumulative under-recovery of $1,247,955, which is the basis for the FYE19 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-CON's true-up filing, Docket No. G011/AA-18-490.

[51] Supporting spreadsheets with detailed calculations are contained in Department Attachments G8 and G9.

[52] MERC has the following classes:

- General Service (GS);
- Small Volume Interruptible (SVI);
- Large Volume Interruptible (LVI);
- Super Large Volume Interruptible (SLVI);
- Small Volume Joint (SVJ);
- Large Volume Joint (LVJ); and

Table G10a - MERC
True-Up Factors per Mcf by System and Customer Class
(As filed by MERC)

Class	NNG	Consolidated
GS	$0.2234	$0.2053
SVJ/LVJ/SLVJ Demand	$0.0000	$0.0000
SVI/SVJ/LVI/LVJ/SLVI Commodity	$0.4068	$0.3036

a. MERC-NNG

The Department's analysis shows that MERC under-recovered its total gas costs on its NNG System by $6,935,845, or approximately 5.23 percent during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – MERC over-recovered its demand costs for the MERC-NNG system by $3,344,249, or approximately 15.71 percent. The demand-cost over-recovery also includes NNG capacity-release revenue of $1,012,012.[53] Without this revenue, there was an over-recovery of demand costs of $2,332,237 or approximately 10.96 percent. In addition to mentioning capacity release revenue and curtailment penalty revenues,[54] MERC explained that the over-collection of demand costs was predominantly caused by actual sales being greater than projected sales. On August 31, 2018, MERC concurrently filed, with the true-up, an Excel spreadsheet that provided an analysis of the over- and under-recoveries.

   As discussed in Section I above, weather across the state during FYE18 was between about two percent warmer than normal to almost four and a half percent colder than normal. In addition, temperatures during the heating season were colder than the annual temperatures at most weather stations. Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-NNG's over-recovery of demand costs appears to be reasonable.

2. Commodity Costs –MERC-NNG under-recovered commodity costs by $10,280,094, or approximately 9.23 percent. The commodity cost under-recovery also includes

- Super Large Volume Joint (SLVJ).

[53] MERC-NNG's AAA Report, Schedule I.
[54] MERC-NNG had minimal daily delivery variances charges (DDVC) penalty revenue in FYE18.

revenue of $248,224 (consisting of balancing revenue of $247,982[55] and penalty revenue of $242[56]). Without these revenues, there was an under-recovery of commodity costs of $10,528,318, or approximately 9.46 percent. MERC stated that "the under collection was predominantly caused by higher than forecasted gas costs." On August 31, 2018, MERC concurrently filed with the true-up, an Excel spreadsheet that provided an analysis of the over and under recoveries.

Considering the price spikes experienced in late December 2017 and into the first week of January 2018, it follows that MERC would have experienced significant under-recovery of its commodity costs. According to the monthly over-/under-recovery analysis spreadsheet provided by MERC, approximately $8.9 million of the under-recovery occurred in December.

Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-NNG's under-recovery of commodity costs appears to be reasonable.

b. MERC-Consolidated

The Department's analysis shows that MERC over-recovered its total gas costs for the Consolidated System by $1,217,321, or approximately 5.86 percent, during the reporting period. This over-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – MERC over-recovered its demand costs for the MERC-CON system by $1,185,304, or approximately 42.01 percent. The demand-cost over-recovery includes capacity-release revenue of $414,618[57] and curtailment penalty revenues of $0.[58] Without the capacity release revenue, there was an over-recovery of demand costs of $770,686, or approximately 27.32 percent. In addition to mentioning capacity release revenue, MERC stated that sales being higher than projected sales contributed to the over-recovery.[59] On August 31, 2018, MERC concurrently filed with the true-up an Excel spreadsheet that provided an analysis of the over- and under-recoveries.

   As discussed in Section I above, weather across the state during FYE18 was between about two percent warmer than normal to almost four and a half percent colder than normal. In addition, temperatures during the heating season

[55] MERC-NNG's AAA Report, Schedule B&E, page 2.
[56] MERC-NNG's AAA Report, Schedule J.
[57] MERC- CON's AAA Report, Schedule I.
[58] MERC-CON's AAA Report, Schedule C and D.
[59] See MERC-CON's AAA Report, page 3.

were colder than the annual temperatures at most weather stations. Volumetrically speaking, sales in December 2017, January 2018, and February 2018 were more than double the projected volumes used to set the monthly demand rates.

Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-CON's over-recovery of demand costs appears to be reasonable.

2. Commodity Costs – MERC-CON under-recovered commodity costs by $2,402,625, or approximately 13.37 percent. The commodity-cost under-recovery also includes balancing penalty revenue of $47,573.[60] Without these revenues, there was an under-recovery of commodity costs of $2,450,198, or approximately 13.64 percent. In its filing, MERC-CON stated that the "under collection was predominantly caused by actual sales being less than projected sales."[61] On August 31, 2018, MERC concurrently filed with the true-up, an Excel spreadsheet that provided an analysis of the over- and under-recoveries.

   Considering the price spikes experienced in late December 2017 and into the first week of January 2018, it follows that MERC would have experienced significant under-recovery of its commodity costs. According to the monthly over-/under-recovery analysis spreadsheet provided by MERC, approximately $1.2 million of the under-recovery occurred in December.

   Based on its review of MERC's analysis of the over- and under-recoveries, the Department concludes that MERC-CON's under-recovery of commodity costs appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket Nos. G007,011/M-06-1358, G007,011/M-09-262, G007,011/M-11-296, G007,011/M-13-207, G011/M-15-231, and G011/M-17-85.[62] In these dockets, the Commission allowed MERC to recover the costs associated with using financial instruments in securing natural gas supplies through the PGA. The *Orders* in these dockets require MERC to report and provide in future

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[60] MERC- CON's AAA Report, Schedule B and E, page 1.
[61] MERC-CON's AAA Report, page 3.
[62] MERC filed a petition requesting *Extension of Rule Variances to Recover the Costs of Financial Instruments Through the Purchased Gas Adjustment* on January 24, 2017 in Docket No. G011/M-17-85. In its Order issued on May 8, 2017, the Commission granted the variance for an additional four years, until June 30, 2021. The Commission also continued the requirement for MERC to provide an annual analysis on its hedging program and a post-mortem analysis in its AAA Reports.

AAA filings data on the relative benefits of price hedging contracts, including the average cost per dekatherm for natural gas purchased using financial instruments compared to the relevant monthly and daily spot index prices, together with the following information:

- a list of each hedging instrument entered into;
- the total contracted volumes, for each instrument; and
- the net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot prices.

The Commission included various other restrictions in its *Orders* and specifically, in its August 17, 2011 *Order* in Docket Nos. G007,011/M-11-296 and G007,011/M-13-207, required MERC to provide, in its AAA Reports, the full post-mortem analysis of their hedged volumes for the preceding heating season compared to other hedging strategies and the prevailing market prices strategy.

MERC included information regarding these *Order* requirements in its AAA Reports, page 2, Schedules L and O and in an Excel spreadsheet filed concurrently with the AAA Report. The Department discusses MERC's hedging costs in Section III, part O, of this Report.

Docket No. G999/AA-08-1011. The Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with the following information about their hedging programs, beginning in fiscal-year 2010:

- a clearly defined and quantified description of the risk (*i.e.,* catastrophic or other type of event) the companies are insuring against by implementing the hedging strategies. The Company also was directed to include a clearly defined and quantified estimate of probability of the events occurring;

- a quantitative analysis of the value of reducing price volatility and managing price risk (the cost and benefit of these programs to all customers and the companies) that includes:
    - a comparison of what actual low, average, and high usage customer bills (on a monthly basis) would have been with and without the use of the hedging strategies as implemented during the relevant time period; and
    - a comparison of what these customer bills would have been under budget billing, assuming normal gas usage for low, average, and high-usage customers, and assuming catastrophically high prices; and,

- a quantitative definition of "catastrophically high prices" (in absolute and relative terms), and a bill analysis that shows how these prices would impact low, average, and high-usage customer bills.

MERC included information regarding these *Order* requirements in its AAA Reports, pages 1-2, and in Schedule P. The Department discusses MERC's hedging costs in Section III, part O, of this Report.

<u>Docket Nos. G999/AA-14-580 and G999/AA-17-493.</u> The Commission's August 24, 2015 *Order* required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. In its February 27, 2019 *Order* in Docket 17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

On page 8-9 of MERC-NNG's AAA Report, MERC stated that there were seven curtailments called and three occurrences of unauthorized gas use by MERC-NNG customers during the time period, down from 12 occurrences in FYE17. MERC reported the required information for those customers and stated that MERC had discussions with each to ensure the curtailment process was understood.[63] No curtailments were called on MERC's Consolidated system during the reporting period.

The Department concludes that MERC complied with the reporting requirements in Docket No. 17-493 on unauthorized gas use.

<u>Docket Nos. G011/M-15-895 and G011/M-18-526.</u> The Commission's May 8, 2018 *Order* in Docket No. 15-895 required MERC to separately track and report Rochester-specific capacity release information (e.g., volumes, revenue received) in future AAA filings in the same manner that it has in previous filings for short-term capacity releases.

On page 5 of MERC-NNG's AAA Report, MERC stated that,

> …the first tranche of additional capacity resulting from the NNG upgrades related to the Rochester Project will be available on November 1, 2018. As a result, none of the additional Rochester Project capacity was available during this AAA reporting period.

The Department concludes that MERC complied with the reporting requirements in Docket Nos. 15-895 and 18-526 on Rochester-specific capacity release.

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[63] In the Order from Docket No. G999/AA-14-580, The Commission required MERC in its next rate case to raise the Company's curtailment penalty from $20 to $50 per dekatherm. MERC did so in Docket No. G011/GR-15-736. The Commission's Order in Docket 15-736 was issued on October 31, 2016, therefore the increased penalty of $5 per therm was first reflected in MERC's filing in Docket No. G999/AA-18-374.

3. Summary and Recommendations

The Department concludes that MERC's FYE18 annual automatic adjustment reports are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept MERC-NNG's true-up filing in Docket No. G011/AA-18-489;
- allow MERC-NNG to implement its true-up, as shown in Department Attachment G8 of this FYE18 AAA Report;
- accept MERC-CON's true-up filing in Docket No. G011/AA-18-490; and
- allow MERC-CON to implement its true-up, as shown in Department Attachment G9 of this FYE18 AAA Report.

D. CENTERPOINT ENERGY

1. Recovery of Gas Costs and True-Up Calculations

On September 4, 2018, CenterPoint Energy submitted its Annual True-Up Report in Docket No. G008/AA-18-573 in compliance with Minnesota Rule 7825.2810. The Department concludes that CenterPoint Energy's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

According to CenterPoint Energy's true-up filing, CenterPoint Energy under-recovered gas costs by $47,266,585, or approximately 8.24 percent, with a cumulative under-recovery of approximately 7.62 percent[64] of its actual gas cost incurred. By customer class, CenterPoint Energy reported under-recoveries for the current reporting period as follows:

[64] The figure of 7.62 percent represents the cumulative under-recovery of $43,738,574, which is the basis for the FYE19 true-up factors. For a detailed breakdown of the true-up calculation, please see CenterPoint Energy's true-up filing, Docket No. G008/AA-18-573.

Table G11 - CenterPoint
FYE18 Percent Over-Recovery/(Under-Recovery) by Customer Class[65]
(As filed by CenterPoint Energy)

Class	
Small Volume Firm	(8.40)
Large General Service	(9.31)
Small Volume Dual Fuel	(6.55)
Large Volume Dual Fuel	(7.07)
Total System	(8.24)

Using the rate-case sales volumes by CenterPoint Energy results in the following proposed true-up factors by class.[66]

Table G11a - CenterPoint
True-Up Factors per Dekatherm (Dth) by Customer Class
(As filed by CenterPoint Energy)

Class	Factor
Small Volume Firm	$0.3620
Large General Service	$0.2643
Small Volume Dual Fuel	$0.2161
Large Volume Dual Fuel	$0.2376

The Department's analysis of CenterPoint Energy's true-up calculation indicates that the current year's deviation between gas-cost recoveries and actual gas costs was primarily caused by the following factors:

1. Demand Costs – CenterPoint Energy under-recovered its demand costs including propane costs[67] by $2,288,575, or approximately 2.67 percent. The demand cost under-recovery includes off-system sales revenue of $287,217 and curtailment revenue of $0.[68] Without these revenues, there was an under-recovery of demand costs of $2,575,792 or approximately 3.00 percent. In its filing,[69] CenterPoint Energy stated that the demand cost under-recovery resulted from weather that was about 4.4 percent colder than normal and firm sales that were about 7.4 million Dth greater than the weather-normalized sales used to calculate the demand recovery factor (actual firm Cycle sales were 118.4 million Dth vs 110.9 million Dth forecasted for the test year firm sales in Docket G008/GR-17-285.)

[65] A supporting spreadsheet with detailed calculations is contained in Department Attachment G10.
[66] See CenterPoint Energy's true up, page 10, for the sales volumes.
[67] Propane costs of $191,325 are included in demand costs. CPE's True-Up, Page 3.
[68] CenterPoint Energy's True-Up Report, Page 9.
[69] See CenterPoint Energy's AAA Report, page 22.

According to CenterPoint Energy, adjustments to demand from the "demand smoothing" factor brought the demand cost recovery much closer to the demand costs incurred, reducing recovery in the period to avoid carrying over a much larger over-recovery due to weather.[70]

As discussed in Section I above, weather across the southern half of the state during FYE18 was between 1.78 percent warmer than normal in Sioux Falls, SD to 1.82 percent colder than normal in St. Cloud. Weather at the Minneapolis/St. Paul weather station, where the majority of CenterPoint Energy's load is concentrated, was near normal for the year and 1.57 percent colder during the heating season. These temperatures would typically predict an over-recovery of demand costs, however, the demand smoothing factor brought recovery closer to actual costs incurred, but flipping recovery from a large over-recovery to a smaller under-recovery. The demand smoothing factor is discussed in more detail in the Compliance and/or Supplemental Reporting Requirements below.

Based on this information, the Department concludes that CenterPoint Energy's under-recovery of demand costs appears to be reasonable.

2. Commodity Costs – CenterPoint Energy under-recovered commodity costs by $44,978,010, or approximately 9.22 percent. The commodity cost under-recovery includes off-system sales revenue of $344,450, damage revenue of $28,853, and balancing revenue of $895,661.[71] Without these revenues, there was an under-recovery of demand costs of $46,246,974 or approximately 9.48 percent. Regarding the under-recovery, CenterPoint Energy stated that "Commodity-cost recovery rates are based on estimated monthly purchases prior to the start of the month, based on the assumption of 'normal' weather. To the extent estimated purchases vary from actual purchases, an over or under recovery will occur."[72]

   CenterPoint Energy also provided further price discussion on pages 10-11 of its Annual Report; in reference to the 2017-2018 winter, CenterPoint Energy stated,

> First-of-Month Market price volatility was one of the highest over recent winters, averaging 74%. CenterPoint Energy's billed gas costs for the winter were more volatile than most years in the last ten years, but much more stable than the market.

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[70] On May 17, 2016, the Commission issued its Order in Docket No. G008/M-16-228 approving CenterPoint's request for a 3-year variance to continue using the smoothing tool, with modifications and reporting requirements.
[71] CenterPoint Energy's AAA Report, Exhibit 9.
[72] See CenterPoint Energy's AAA Report, page 22.

Based this information, and on the discussion in Section I of volatile prices in the December/January time frame, the Department concludes that CenterPoint Energy's under-recovery of commodity costs appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket Nos. G008/M-00-980, G008/M-03-782, G008/M-05-1196, G008/M-07-1063, G008/M-10-857, G008/M-13-728, and G008/M-16-228 (Demand Adjustment Program). In Docket No. G008/M-00-980, CenterPoint Energy requested a three-year pilot program to add a monthly Demand Adjustment Program (Program) to its demand cost recovery rate charged to firm customers in order to provide a better matching of costs and recoveries within the true-up year. In its October 27, 2000 *Order*, the Commission approved the pilot program and required CenterPoint Energy to provide, in its Annual Automatic Adjustment Report, a summary of what the total annual demand-cost recovery would have been absent the Demand Adjustment, the total amount of Demand Adjustment collected, and the total amount of demand costs that will be trued up.[73] In the above-listed dockets, the Commission approved extensions of the Program. In its December 11, 2013 *Order*,[74] the Commission approved CenterPoint Energy's request "to remove the one-month lag in sales from its calculation" of the monthly demand adjustment and ordered continuing reporting requirements from the previous dockets.[75] The Program was again approved by the Commission in Docket No. G008/M-16-228, with no changes from the December 11, 2013 *Order*.[76]

In Exhibits 3 and 4 of its AAA Report, CenterPoint Energy included the required information.[77] Since the inception of the Program, the demand-cost recovery results have been as follows:[78]

[73] CenterPoint Energy's Demand Adjustment was not charged to its Viking area customers until consolidation of the PGAs in 2005.
[74] Docket No. G008/M-13-728.
[75] Prior to FYE14, this approach was reported as a hypothetical removal of the one-month lag filed in CenterPoint Energy's AAA Reports, Exhibit 4.
[76] Docket No. G008/M-13-728.
[77] See CenterPoint Energy's AAA Report, page 19 for a discussion.
[78] The data in Table G12 does not include "No Surprise Bill©" (NSB) customer data starting with November 2001 until termination of the program in December 2007. NSB customer demand costs were recovered on weather-normalized sales and a fixed recovery rate.

Table G12: CenterPoint's Demand Adjustment Program Recovery Results[79]

	With Program[80]		Without Program	
Year	Over/(Under)[81]	Percent	Over/(Under)	Percent
FYE01	$(1,859,854)	(1.6)	$6,060,569	5.2
FYE02	$2,140,282	2.1	($9,835,529)	(9.6)
FYE03	$195,409	0.2	$7,784,072	7.9
FYE04	$(1,167,912)	1.0	$(1,197,490)	(1.0)
FYE05	$(934,612)	(0.8)	$(1,530,385)	(1.3)
FYE06	$(406,837)	(0.4)	$(12,087,038)	(10.4)
FYE07	$7,519,994	7.0	$(286,342)	(0.3)
FYE08	$2,511,582	2.9	$1,322,689	1.5
FYE09	$3,098,947	4.7	$4,489,569	6.8
FYE10	$(5,149,579)	(6.6)	$(7,327,401)	(9.4)
FYE11	$1,164,918	1.5	$3,903,613	5.1
FYE12	$(4,482,056)	(6.0)	$(11,272,158)	(15.1)
FYE13	$7,310,268	10.0	$5,025,956	6.9
FYE14[82]	$688,175[83]	0.9	$11,295,219	15.4
FYE15	$1,882,416	2.4	$7,712,926	9.8
FYE16	$(2,720,436)	(3.4)	$(873,556)	(1.1)
FYE17	$(6,726,160)	(7.8)	$(6,610,120)	(7.7)
FYE18	$(1,715,132)	(2.0)	$9,655,090	11.3

As highlighted above, except for FYE07, FYE08, FYE13, FYE16, and FYE17, the program provided a better match of costs and recoveries within the true-up year than would have been the case without this program.[84] In FYE18, actual under-recovery of $1,715,132 was a closer match to costs than the hypothetical over-recovery of $9,655,090. Although demand smoothing does not always outperform the hypothetical recovery without the program, the Program does improve the match between costs and recoveries in most years. The Department refers to

[79] From CenterPoint Energy's AAA Report Exhibits 3 and 4.
[80] Program recovery did not include the lag adjustment until FYE14.
[81] For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar-month data rather than billing-month data).
[82] Beginning in FYE14, the Commission approved CenterPoint Energy's request to adjust the Program for a one-month lag in sales.
[83] This figure was corrected. As of FYE14, the Program recovery includes the lag adjustment.
[84] Regarding FYE07, the Commission modified the pilot program in its December 24, 2007 *Order* to account for capacity-release credits due to the large over-recovery in FYE07. The over-recovery was larger due to adding capacity-release credits for the first time starting in January 2008. For FYE08, the demand cost adjustment was not in place for three months (October through December of 2007) since CenterPoint Energy's request for a continued variance in Docket No. G008/M-07-1063 was not approved until December 24, 2007. Thus, the results of the FYE08 demand cost adjustment program may not be indicative of what the results would have been over the full eight months of the program.

Docket G008/M-16-228 for the analysis supporting the Commission's decision to grant the most recent variance to allow the demand smoothing adjustment to continue.

As stated above, the Commission required CenterPoint to continue reporting requirements from previous dockets. Table G12a shows the over/(under) recovery with and without a 1-month lag adjustment.

Table G12a: CenterPoint's Demand Adjustment Program One-Month Lag Adjustment Results[85]

Year	With Lag Adjustment Over/ (Under) Recovery	Without Lag Adjustment Over/ (Under) Recovery
FYE08	$939,032	$1,322,689
FYE09	$3,873,820	$3,098,947
FYE10	$(4,394,252)	$(5,149,579)
FYE11	$2,306,874	$1,164,918
FYE12	$(4,568,677)	$(4,482,056)
FYE13	$3,954,396	$5,025,955
FYE14[86]	$688,175	$(149,278)
FYE15	$1,882,416	$(285,002)
FYE16	$(5,589,748)	$(2,720,436)
FYE17	$(10,981,399)	$(6,726,160)
FYE18	$(4,873,824)	$9,655,090

In FYE18, the hypothetical $4,873,824 under-recovery assuming a one-month lag adjustment methodology reflects a better result than the actual methodology without the lag adjustment over-recovery of $9,655,090. The Department concludes that CenterPoint Energy complied with the filing requirements in the Commission's *Order* in Docket No. G008/M-16-228.

Docket Nos. G008/M-01-540, G008/M-08-777, G008/M-12-166, and G008/M-15-912 (Financial Call Options). In Docket No. G008/M-01-540 (Docket No. 01-540), the Commission granted a variance to allow CenterPoint Energy to recover costs associated with financial call options related to swing gas in place of reservation fees through the PGA. The Commission granted an extension of the variance through June 30, 2010 in Docket No. G008/M-08-777 (Docket No. 08-777). Further, the Commission granted an additional extension of the variance through June 30, 2016 and required compliance reports in Docket No. G008/M-12-166. In Docket No. G008/M-15-912 (Docket No. 15-912), CenterPoint Energy was granted an extension to its

[85] From CenterPoint Energy's AAA Report Exhibits 3 and 4.
[86] Beginning in FYE14, the Commission approved CenterPoint Energy's request to adjust the Program to remove the one-month lag. The Commission required CenterPoint Energy to continue to report "the Company's monthly demand adjustment compared to a hypothetical demand-cost recovery rate that reflects a one-month lag."

variance to recover the costs associated with certain financial instruments through the PGA through June 30, 2020.

In its November 3, 2004 *Order Granting Open-Ended Variance to Minn. Rules, Parts 7825.2400, 7825.2500, and 7825.2700* (01-540), the Commission required CenterPoint Energy to:

- include information on the call options contracts and swing contracts with reservation fees used during the year and the price paid for natural gas through each of these types of contractual arrangements; and
- compare the cost of the swing gas actually used with the cost for natural gas in the spot market for the day on which the swing gas was actually used.[87]

In its March 6, 2009 *Order* (08-777), the Commission required the following reporting requirements:

- data on the specifics of any price hedging contracts, including a list of each hedging instrument entered into;
- the totals contracted for each instrument; and
- the net gains or losses, including all transaction costs.

In its Exhibit 6, CenterPoint Energy included information on its swing contracts only, as it did not purchase financial call options. CenterPoint Energy's Exhibit 7 lists hedge volumes and Exhibit 8 estimates impacts on customer bills as a result of using hedging products in its supply portfolio during the true-up period.[88]

The Department concludes that CenterPoint Energy complied with the filing requirements in Docket Nos. 01-540, 08-777, and 15-912. The Department discusses CenterPoint Energy's hedging costs in Section III, part O, of this FYE18 AAA Report.

Docket No. G999/AA-08-1011. As noted above, the Commission directed CenterPoint Energy, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal year 2010. CenterPoint Energy provided this information in pages 23-25, as well as in Exhibit 8 of its Annual Report. The Department concludes that CenterPoint Energy complied with the filing requirements in Docket No. G999/AA-08-1011. The Department discusses CenterPoint Energy's hedging costs in Section III, part O, of this FYE18 AAA Report.

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[87] In Docket No. G999/AA-16-524, CenterPoint Energy explained that during the winter, its swing gas is valued the same as "spot market" gas, so there is no comparison to provide. The Company requested to discontinue this compliance item until such time that the difference is not zero. The Commission approved CenterPoint Energy's request.

[88] With further discussion in Section 6.4, pages 23-25.

Docket No. G008/GR-08-1075 (Off-System Sales). In Docket No. G008/GR-08-1075 (08-1075), CenterPoint Energy was ordered to return "off-system sales" revenues to ratepayers through an initial refund of $5,912,279 and then continue to refund any off-system revenues through subsequent PGA filings. In its November 2, 2009 *Findings of Fact, Conclusions of Law, and Recommendation*, the Commission's Ordering Paragraph 72 (d) required CenterPoint Energy to "include a separately identified calculation of the over-/under-recovery of the off-system sales credits to ratepayers and of the incentive" in its annual AAA filing. Ordering Paragraph 72 (c) required that the off-system sales be split between commodity and demand gas costs (*i.e.*, storage exchange and swing sales would be a demand cost credit and other point exchanges would be a commodity cost credit).

CenterPoint Energy included the required information on pages 9 and 13 of its annual true-up filing. Upon review of this information, the Department concludes that CenterPoint Energy's incentive on off-system sales[89] and allocations among classes were calculated correctly. Thus, the Department concludes that CenterPoint is in compliance with the filing requirements in Docket No. 08-1075.

Docket Nos. G999/AA-14-580 and G999/AA-17-493. The Commission's August 24, 2015 *Order* in Docket No. 14-580 required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. In its February 27, 2019 *Order* in Docket 17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

On page 20 of its AAA Report, CenterPoint Energy stated that, "The Company did not have any unauthorized gas used or billed in the 2017-2018 gas year."

The Department concludes that CenterPoint Energy complied with the reporting requirements in Docket No. 17-493.

3. Summary and Recommendations

The Department concludes that CenterPoint Energy's FYE18 annual automatic adjustment report is complete with respect to the filing requirements in Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

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[89] In Docket No. G008/GR-08-1075, the Commission allowed CenterPoint Energy to earn an incentive equal to the approved overall rate of return on its off-system sales. On page 13 of its True-Up filing, CenterPoint Energy's incentive totaled $24,936 ($308,241-283,305).

- accept CenterPoint Energy's FYE18 true-up, Docket No. G008/AA-18-573; and
- allow CenterPoint Energy to implement its true-up, as shown in Department Attachment G10 of this FYE18 AAA Report.

E. XCEL GAS

1. Recovery of Gas Costs and True-Up Calculations

On August 31, 2018, Xcel Gas submitted its annual true-up filing, Docket No. G002/AA-18-572 in compliance with Minnesota Rule 7825.2810. Based on its review, the Department concludes that Xcel Gas' filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

According to its true-up filing, Xcel Gas under-recovered gas costs by $4,296,016, or approximately 1.56 percent, during the reporting period, with a cumulative under-recovery of approximately 0.09 percent.[90] By customer class, Xcel Gas reported under-recoveries for the current reporting period as follows:

Table G13 - Xcel Gas
FYE18 Percent Over-Recovery/(Under-Recovery) by Customer Class[91]
(As filed by Xcel Gas)

Class	
Residential	0.06
Commercial/Industrial (C/I)	(1.14)
Demand Billed	4.30
Demand Billed Commodity	(6.24)
Small Interruptible (SVI)	(6.78)
Medium & Large Interruptible (M&LVI)	(9.01)
Total	(1.56)

Using the sales volumes forecasted by Xcel Gas for the year ending August 31, 2019[92] results in the following true-up factors by class, as calculated by Xcel Gas in its filing:

[90] The figure of 0.09 percent represents the cumulative under-recovery of $245,039, which is the basis for the true-up adjustments. For a detailed breakdown of the true-up calculations, please see Xcel Gas' true-up filing, Docket No. G002/AA-18-572.
[91] Supporting spreadsheets with detailed calculations are contained in Department Attachment G11.
[92] Xcel Gas' true up, Schedule B, page 2.

Table G13a – Xcel Gas
True-Up Factors per Dekatherm (Dth) by Customer Class
(As filed by Xcel Gas)

Class	
Residential	$(0.00533)
C/I[93]	$(0.00097)
Demand Billed Demand	$(0.02296)
Demand Billed Commodity	$0.01195
SVI	$0.01583
M&LVI	$0.02126

The Department's analysis of Xcel Gas' true-up calculation shows that the current year's deviation between Xcel Gas' gas cost recoveries and actual gas costs was primarily caused by the following factors:

1. **Demand Costs including Demand Billed costs:** Xcel Gas over-recovered Minnesota demand costs by $4,167,485, or approximately 8.76 percent. The demand cost over-recovery also includes interruptible curtailment penalty revenue of $1,266,073 and capacity release revenue of $632,132.[94] Without these revenues, there was an over-recovery of demand costs of $2,269,280 or approximately 4.77 percent. According to Xcel Gas, actual FYE18 sales were approximately 10.32 percent higher than forecasted sales in the monthly PGA, resulting in the over-recovery of demand costs.[95]

   As discussed further below, Xcel Gas has a Monthly Demand Cost True-Up Mechanism, approved in Docket No. G002/M-03-843. This mechanism is designed to offset swings in revenue collection caused by deviations from the forecasted normal weather. The mechanism credited $3,458,025 of demand costs from customers during the FYE18 heating season due to weather and the cap on the amount of the adjustment per month. Xcel Gas stated that without the mechanism, its over-recovery of demand costs would have been approximately 16.03 percent.[96]

[93] The true-up factor for the C/I class is a credit rate, despite Xcel Gas under-recovering gas costs from this class in FYE18, which would normally result in a surcharge. This is a result from the "High Bridge Adjustment" that is discussed below in Section III.K. Lost-and-Unaccounted for Gas.
[94] Xcel Gas' responses to Department Information Request Nos. 8 and 6.
[95] Xcel Gas' AAA Report, Attachment B, Schedule 3, page 3.
[96] Xcel Gas' AAA Report, Attachment B, Sch. 3, p. 3 and true up, Schedule I.

Weather in Fargo during FYE18 was 1.25 percent colder than normal, and in St. Cloud was 1.82 percent colder than normal. At the Minneapolis/St. Paul weather station, where the majority of Xcel Gas's load is concentrated, annual temperatures were near normal at 0.01 percent warmer than normal but 1.57 percent colder during the heating season. Coupled with the large amount of revenue credited from curtailment penalties, plus additional revenue from capacity release, the Department concludes that Xcel Gas' demand cost over-recovery appears to be reasonable.

2. **Commodity Costs (including peak-shaving costs):** During FYE18 Xcel Gas under-recovered commodity costs by \$8,463,501, or about 3.72 percent. The commodity-cost under-recovery also includes balancing penalty revenue of \$100,019.[97] Without this revenue, there was an under-recovery of commodity costs of \$8,563,520 or approximately 3.77 percent. Xcel Gas stated that the under-recovery was due to:[98]

> …deviations between monthly forecasted prices and actual wholesale commodity gas prices. The price deviations between monthly price estimates and actual unit cost were the result of price volatility in the wholesale natural gas commodity market. On an average unit basis, the under-recovery is approximately 1.1 cents per therm. Because customer consumption varies by class from month to month and price deviation varies from month to month, individual classes had varying results.

Based this information, and on the discussion in Section I of volatile prices in the December/January time frame, the Department concludes that Xcel Gas's under-recovery of commodity costs appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G002/M-94-103. The Commission required Xcel Gas to return all past, present, and future capacity release revenue from all sources to firm customers using Federal Energy Regulatory Commission (FERC) Account 805.1. Based on Xcel Gas' true up Schedule H, Xcel Gas complied with the Commission's *Order* by returning capacity-release revenue from all sources to firm customers.

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[97] Xcel Gas' True-Up Report, Schedule D, page 1 and Xcel Gas' response to Department Information Request No. 9.
[98] Xcel Gas' AAA Report, Attachment B, Schedule 3, pages 3-4.

Docket No. G002/M-98-1429. The Commission required Xcel Gas to return to ratepayers, in the same manner as penalties are handled, all “additional charge” money (curtailment penalty revenue) received by Xcel Gas under Section 5, sheet 8, of its tariffs for large firm transportation customers’ failure to restrict the use of gas. Xcel Gas indicated, on page 3 of Attachment G in its AAA report, that no firm transportation customers incurred “additional charges” for unauthorized use of gas, and Xcel Gas did not receive any “additional charges” monies during the current true-up period.

Docket Nos. G002/M-01-1336, G002/M-03-1627, G002/M-08-46, G999/AA-06-1208, G002/M-12-519, and G002/M-16-88 (Hedging). Xcel Gas requested to continue its PGA rule variance to recover hedging costs through June 30, 2020 in the PGA in Docket No. G002/M-16-88. As a condition of approving and extending rule variances to allow Xcel Gas to include the costs of financial hedging instruments in its PGA, the Commission required Xcel Gas to identify the following, separately, in future AAA reports:

- data on the relative benefits of price-hedging contracts, including the average cost per dekatherm for natural gas purchased under financial instruments compared to the comparable monthly and daily spot index prices;
- a list of each hedging instrument entered into;
- the total volumes contracted for, for each instrument;
- the net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot index prices; and
- a schedule of hedging costs.

Xcel Gas complied by submitting the required information in its Attachment A, Schedule 5, and Attachment G, Schedule 2 of its AAA report and Schedule H of Xcel’s true-up filing. The Department discusses Xcel Gas’ hedging costs in Section III, part O, of this FYE18 AAA Report.

Docket Nos. G002/M-03-843, G002/M-06-681, G002/M-08-456, G002/M-11-203, G002/M-14-171, and G002/M-17-101 (Demand Cost Mechanism). On June 11, 2004, the Commission approved a Monthly Demand-Cost True-Up Mechanism, with requirements, and granted Xcel Gas a variance to Minnesota Rule 7825.2700, subpart 5 until September 30, 2006. The Monthly Demand-Cost True-Up Mechanism was implemented in October 2004. In the above dockets, the Commission approved extensions of the program until September 30, 2020.

The mechanism should result in billing rates that are:

- Lower than rates without the mechanism when there is colder-than-normal weather (when natural gas consumption and customer bills are high); and

- Higher than without the mechanism when there is warmer-than-normal weather (when natural gas consumption and customer bills are low).

The Demand Cost Mechanism is adjusted by capacity release as approved in Docket No. G002/M-11-203. The mechanism in place includes caps on the monthly amount. For April through October, the cap is 25 percent of the demand cost recovery rate. The cap for November through March is 125 percent of the levelized demand rate minus the actual demand cost recovery rate. With respect to annual filings, the Commission required Xcel Gas to identify (by customer class) the monthly demand true-up revenues and summarize the following for each firm non-demand billed customer class in Xcel Gas' annual true-up filings:

- the annual demand cost recovery absent the adjustments;
- the total annual adjustment recovery; and
- the remaining current year demand cost recovery true-up balance.

Xcel Gas' FYE18 true-up filing, Schedule I, includes the required information on the Demand Cost Mechanism results. Since the inception of this program, the demand cost recovery results have been as follows:

Table G14 – Xcel Gas
Monthly Demand-Cost True-Up Recovery Mechanism Results

	With Program Recovery		Without Program	
Year	**Over/(Under)[99]**	**Percent**	**Over/(Under)**	**Percent**
FYE05	$(652,620)	(1.1)	$(3,719,363)	(6.0)
FYE06	$(3,190,837)	(6.0)	$(6,327,057)	(11.9)
FYE07	$4,350,806	8.3	$703,577	1.3
FYE08	$2,628,294	6.1	$3,496,826	8.1
FYE09	$2,433,476	5.5	$3,595,452	8.1
FYE10	$341,457	(0.74)	$846,099	(1.82)
FYE11	$1,784,013	3.71	$2,538,677	5.27
FYE12	$(4,963,775)	(9.96)	$(7,529,571)	(15.11)
FYE13	$2,376,086	4.74	$2,069,183	4.12
FYE14	$7,394,847	15.11	$10,989,489	22.45
FYE15	$2,525,679	5.52	$4,505,962	9.85
FYE16	$(2,638,930)	(5.43)	$(5,530,911)	(11.47)
FYE17	$(996,915)	(2.09)	$(2,881,719)	(6.05)
FYE18	$4,167,484	8.76	$7,625,510	16.03

[99] For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar month rather than billing month data). Excludes demand-billed demand.

As shown above, except for FYE07 and FYE13, the program continues to match costs better within the true-up year than would have been the case without this program. In FYE18 actual over-recovery of $4,167,484 outperformed the hypothetical over-recovery of $7,625,510. The Department concludes that Xcel Gas complied with the filing requirements in the Commission's *Order* in Docket No. G002/M-03-843.

Docket Nos. E,G999/AA-08-1011 and G999/AA-14-580. As noted above, the Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal year 2010. Xcel Gas provided this required information in Attachment G, Schedules 2 through 5 in its AAA Report filing. The Department discusses Xcel Gas' hedging costs in Section III, part O, of this Report.

Docket Nos. G002/M-09-852 and E,G002/M-15-618. On February 18, 2010 in Docket G002/M-09-852, the Commission approved Xcel Gas' Capacity Utilization Program for its gas distribution and electric generation business units as a three-year pilot program and required Xcel Gas to report in the AAA each individual transaction showing quantities and cost, the specific accounting entries and a brief explanation of the transaction. The pilot expired on February 18, 2013. In Docket No. E,G002/M-15-618, the Commission approved the Capacity Utilization Plan as a permanent program and accepted Xcel's agreement to continue to report on the transactions related to the Capacity Utilization Plan annually in its AAA Report. The approved Capacity Utilization Plan includes both natural gas and electric transactions.

During FYE18, the Capacity Utilization Plan resulted in net savings to Xcel Gas of approximately $140,738 and savings to Xcel Electric of approximately $127,141 from avoided storage fees.[100]

The Department concludes that Xcel Gas is in compliance with the filing requirements in Docket Nos. G002/M-09-852 and E,G002/M-15-618.

Docket Nos. G999/AA-14-580 and G999/AA-17-493. The Commission's August 24, 2015 *Order* in Docket 14-580 required all Minnesota regulated natural gas utilities to provide information for the next three AAA reports (2014-2015, 2015-2016, and 2016-2017) on unauthorized gas use for each customer that did not comply with a called interruption during the heating season. In its February 27, 2019 *Order* in Docket 17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

Xcel Gas provided information in a supplemental filing submitted March 22, 2019, in compliance with the Commission's *Order* in Docket 17-493. Xcel Gas reported 289,157 therms of unauthorized gas billed in the 2017-2018 gas year. Xcel Gas also detailed its communication procedures to avoid or address unauthorized use.

[100] Xcel Gas' AAA Report Attachment G, pages 10-11.

The Department concludes that Xcel Gas complied with the Commission's *Order* in Docket No. 17-493 on unauthorized gas use.

Docket Nos. G002/M-15-149, G002/M-16-396, and G002/M-17-510. The Commission's October 21, 2015 *Order* and July 19, 2016 *Order* required that Xcel Gas shall list the Kansas natural gas storage tax costs and revenues as separate line items in the AAA and PGA true-up reports as well as in true-up report Schedules C and D (page 1-2 of 4, and page 4 of 4). Additionally, Xcel Gas is required to submit a report detailing the total amount paid to Kansas and collected from ratepayers during the gas year.

Xcel Gas reported this information in its AAA Report, Attachment G, page 13. Xcel Gas stated that,

> The Minnesota share of the Kansas natural gas storage-related ad valorem tax costs for the years 2009-2014 is $5,006,347, of which $1,000,338 was amortized for the July 2017 to June 2018 gas year. The total amount of tax recovered from Minnesota gas ratepayers for this lump sum tax assessment during the July 2017 to June 2018 gas year is $1,106,295.
>
> The Company was assessed $813,259 in Kansas natural gas storage-related ad valorem tax costs in 2017, of which $702,314 was allocated to Minnesota. …
>
> The total amount of tax collected from Minnesota gas ratepayers during the July 2017 to June 2018 gas year is $663,668. Table 7 below provides a line item summary of the Kansas natural gas storage-related ad valorem tax expenses and revenues.

The Department concludes that Xcel Gas complied with the Commission's Orders in Docket Nos. G002/M-15-149, G002/M-16-396, and G002/M-17-510.

3. Summary and Recommendations

The Department concludes that Xcel Gas' filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept Xcel Gas' FYE18 true-up, Docket No. G002/AA-18-572; and
- allow Xcel Gas to implement its true-up, as shown in Department Attachment G11 of the FYE18 AAA Report.

III. ADDITIONAL INFORMATION

A. AVERAGE ANNUAL RESIDENTIAL CUSTOMER BILLS

Using data supplied by the utilities in their responses to Department Information Request No. 1, the Department compared the average annual bills of residential customers for each regulated gas utility in Minnesota. This information is summarized in Graph 1 below and in Department Attachment G13. As in previous reports, and for comparison purposes, the Department developed a typical residential customer's annual bill for each utility, by system, based on the following:

- customer charge;
- per-unit energy consumption rate; and
- average customer consumption of 140 Mcf per year.[101]

In general, a residential customer pays a fixed monthly customer charge and a per-unit energy consumption rate. The per-unit energy consumption rate can be broken down into gas costs and non-gas costs. The level of non-gas costs (referred to as the margin, or gross margin) is approved by the Commission in the utilities' most recent general rate case.[102]

The gas cost for a firm customer includes both demand costs and commodity costs. The demand cost is the amount a utility pays for the right to reserve pipeline capacity or transportation. Demand levels change only with Commission approval of changes proposed in a miscellaneous demand-entitlement filing.[103] However, as interstate pipelines change the rates that they charge or the cost of gas rates change, Minnesota gas utilities automatically pass on these rate changes to their customers through the PGAs.

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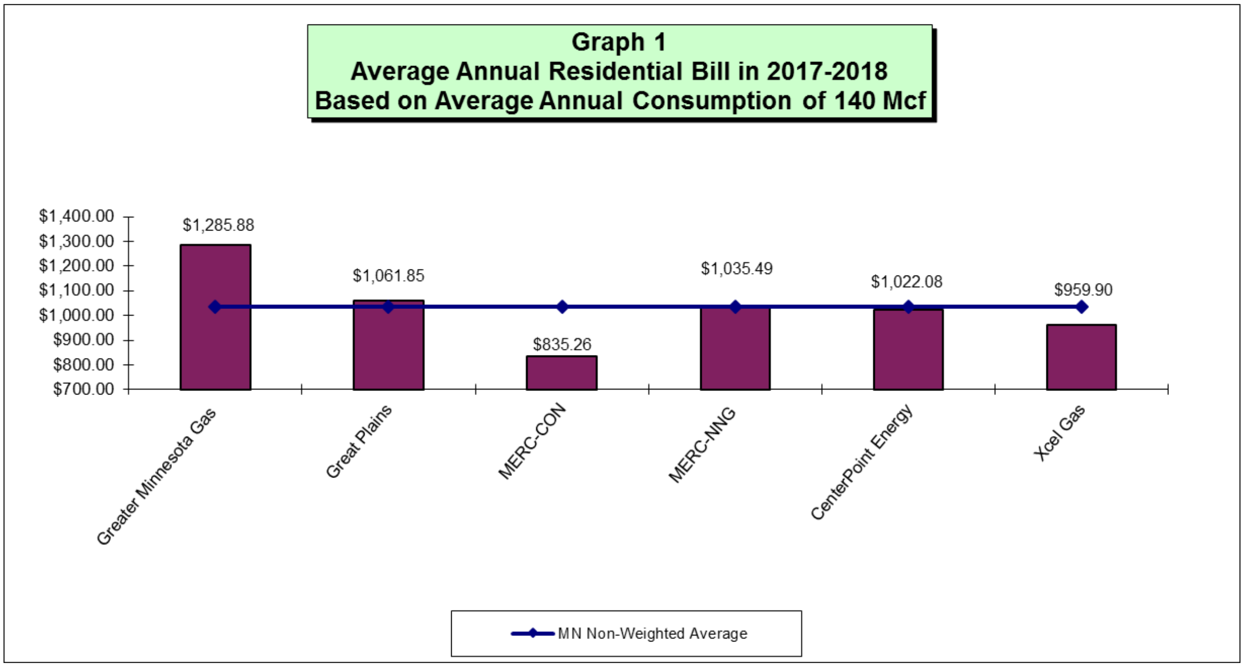
[101] The Department notes that the residential non-weighted average consumption of gas has been lower than 140 Mcf due to decreases in overall natural gas consumption in recent years. The Department continues to use the level of 140 Mcf to allow for comparisons of information among the various years of the Department's AAA reports.

[102] See Section III, part C, for a discussion of margins. Please note that the margins used to calculate total average annual bill are the average rate for the reporting period.

[103] Minnesota LDCs generally file demand entitlement petitions on, or about, July or August 1 of each calendar year, and are typically updated on November 1. However, demand entitlement filings during other parts of the year can also occur.



Graph 1 shows that, based on a consumption level of 140 Mcf, average annual residential bills[104] range from a high of $1,285.88 for customers served by GMG to a low of $835.26 for customers served by MERC-Consolidated.

Table G15 below shows the actual average residential bills and average use for each system during the present reporting period using the data supplied in response to Department Information Request No. 1.[105]

[104] Amounts shown in Graph 1 are not actual averages for customers on any system, since actual averages for each utility depend on actual average consumption levels. Graph 1 is intended to provide a baseline usage comparison that does not vary between years since consumption is held constant at 140 Mcf.
[105] Responses are available upon request.

Table G15: Average Annual Residential Bill and Average Use per Utility for the FYE18 Reporting Period

Utility	System	Average Usage Rankings[106]	Average Use[107] (Mcf)	Annual Bill Rankings	Total Annual Bill ($)	Average Cost per Mcf[108] ($)	Annual Customer Charges ($)
Greater Minnesota		**2**	87.0	**6**	$837.70	$9.63	$102.00
Great Plains		**1**	84.6	**3**	$677.27	$8.01	$90.00
MERC	CON	**5**	91.8	**1**	$588.47	$6.41	$118.44
	NNG	**4**	91.6	**4**	$718.25	$7.84	$118.44
CenterPoint Energy		**6**	94.8	**5**	$732.53	$7.73	$125.25
Xcel Gas		**3**	91.0	**2**	$661.73	$7.27	$108.00

As shown in Table G15, based on actual consumption, CenterPoint Energy experienced the highest average consumption (94.8 Mcf), and GMG had the highest average annual residential bill ($837.70) during FYE18.[109]

Regarding the information provided in Graph 1, Table G15, and Department Attachment G13, the Department notes that costs that utilities incur often are determined by a number of

[106] The rankings throughout this report are listed in the format from lowest to highest (*e.g.,* average use, cost, and rate).
[107] The average annual usage amount reported in response to Department Information Request No. 1 is not weather normalized but reflects the different heating degree days based on location.
[108] The average cost per Mcf may be different from the annual bill shown in column (6) divided by the average use shown in column (4) due to rounding of the average usage.
[109] Since FYE09, the following utilities had the highest consumption and average residential bills, respectively:
FYE09 CenterPoint Energy and Great Plains Crookston .... 97 Mcf $1,045.63
FYE10 CenterPoint Energy/Interstate Gas and GMG................... 88 Mcf $819.99
FYE11 CenterPoint Energy and GMG.. 95 Mcf $977.39
FYE12 MERC-NMU and GMG.......... .... 77 Mcf $735.34
FYE13 CenterPoint Energy and GMG.. 94 Mcf $916.96
FYE14 CenterPoint Energy and GMG.. 106 Mcf $1,154.10
FYE15 CenterPoint Energy and GMG.. 92 Mcf $893.32
FYE16 CenterPoint Energy and GMG.. 79 Mcf $707.43
FYE17 CenterPoint Energy and GMG.. 81 Mcf $704.72
FYE18 CenterPoint Energy and GMG.. 95 Mcf $837.70
GMG continues to have the highest average residential bills, due to its high non-gas margin. Please see Table G18 for more detail.

factors, such as: load factor, number of customers, mix of firm and interruptible customers, number of available pipeline systems, weather, past contracts with pipelines and suppliers that are still in effect, access to storage, and provisions of pipeline service as approved by the FERC (*e.g.*, imbalance penalties).

Second, the non-gas portion of the rate (base rate) is developed independently in a general rate case, and utilities file their rate cases at times chosen by the utility. Base rates reflect the cost, based on the test year, of delivering natural-gas service. These non-gas costs are affected by the service territory, customer mix and density, timing of the rate case, and other factors. The Department highlights some of these differences between utilities in the following sections.

B. ANNUAL AVERAGE GAS COSTS

Table G16 below compares the total system annual averages of both the PGA recovered and the actual incurred commodity costs. The figures in Table G16 represent the per-Mcf[110] commodity costs incurred by the utilities and passed on to ratepayers in the monthly PGAs, as reported in the utilities' true-up filings. Certain tables in this report provide the Minnesota weighted average and the Minnesota non-weighted average amounts. The Department includes the non-weighted average since the weighted average is dominated by Minnesota's largest natural gas provider, CenterPoint Energy.

Table G16: FYE18
Total Weighted Average Cost of Commodity
PGA Recovered Versus Actual Incurred[111]

Utility	System	Recovered PGA Commodity Rate ($/Mcf)	Actual Annual Commodity Rate ($/Mcf)	Percent Over/ (Under) Recovery
Greater Minnesota		$ 3.1241	$ 3.2378	(3.51)%
Great Plains		$ 3.0781	$ 3.6461	(15.58)%
MERC	CON	$ 2.5403	$ 2.9324	(13.37)%
	NNG	$ 3.4421	$ 3.7923	(9.23)%
CenterPoint Energy		$ 3.2867	$ 3.6203	(9.22)%
Xcel Gas		$ 2.9043	$ 3.0166	(3.72)%
Weighted MN Average		**$ 3.1677**	**$ 3.4405**	**(7.93)%**
Non-Weighted MN Average		**$ 3.0626**	**$ 3.3743**	**(9.24)%**

[110] The Department uses Mcf (one thousand cubic feet) in certain areas of its tables to represent units even though the units may actually be Dth (heat-adjusted Mcf).
[111] The numbers used and the detailed calculations are contained in Department Attachment G15.

Table G16 demonstrates that all of the PGA systems under-recovered FYE18 commodity costs. During the reporting period, Great Plains had the greatest under-recovery of commodity costs, with an under-recovery of 15.58 percent. Greater Minnesota and Xcel Gas were the only PGA systems with under-recoveries of less than five percent.

Table G16a below shows the FYE18 increase or decrease in the Minnesota non-weighted average commodity costs over previous years' costs since FYE99. The figures below are nominal costs and are not adjusted for either inflation or weather conditions. Based on these data, during FYE18, the actual Minnesota non-weighted average commodity cost of gas was $3.3743 per Mcf, which represents an approximately one percent decrease in prices from the FYE17 reporting period. The FYE18 commodity cost level is the fifth lowest non-weighted average price in the previous 20 years.

Table G16a: Non-Weighted Average Commodity Costs

Reporting Period	Rate ($/Mcf)	Percent Increase (Decrease) vs. Prior Years
FYE18	$3.3743	
FYE17	$3.4053	(1%)
FYE16	$2.9051	16%
FYE15	$4.1574	(19%)
FYE14	$5.4831	(38%)
FYE13	$3.4442	(2%)
FYE12	$3.5238	(4%)
FYE11	$4.3001	(22%)
FYE10	$4.7259	(29%)
FYE09	$6.1826	(45%)
FYE08	$7.4936	(55%)
FYE07	$7.6177	(56%)
FYE06	$8.8345	(62%)
FYE05	$6.3167	(47%)
FYE04	$5.3364	(37%)
FYE03	$4.7441	(29%)
FYE02	$2.6524	27%
FYE01	$6.0288	(44%)
FYE00	$2.5356	33%
FYE99	$1.9876	70%

As shown above in Table G16, the analysis of "PGA Recovered versus Actual Incurred," a commodity cost comparison provides only a partial picture of a utility's gas-purchasing operations. The Department also used the demand cost information submitted by the utilities in their annual true-up reports to develop a "total system" average cost of gas analysis as shown below in Table G17. The comparison of total costs per Mcf experienced by each utility presents another useful analytical tool to compare recovered versus actual gas costs. Below is a summary of the actual total system gas costs experienced during the reporting period by Minnesota gas utilities.

Table G17: FYE18
Total System Gas Costs (Demand and Commodity)[112]

Utility	PGA Recovered ($/Dth)	Rank	Current-Period Actual incurred Gas Cost ($/Dth)	Rank	Actual Over/(Under) ($/Dth)	Percentage Over/(Under) Recovery
Greater Minnesota	$ 3.7776	**3**	$ 3.8813	**3**	$ (0.1038)	(2.67%)
Great Plains - Consolidated	$ 4.0190	**5**	$ 4.4691	**5**	$ (0.4501)	(10.07%)
MERC						
CON	$ 3.1942	**1**	$ 3.3929	**1**	$ (0.1987)	(5.86%)
NNG	$ 4.2810	**6**	$ 4.5173	**6**	$ (0.2362)	(5.23%)
CenterPoint Energy	$ 3.9050	**4**	$ 4.2441	**4**	$ (0.3391)	(7.99%)
Xcel Gas	$ 3.5911	**2**	$ 3.6481	**2**	$ (0.0570)	(1.56%)
MN Weighted Avg.	**$ 3.8383**		**$ 4.0775**		**$(0.2392)**	**(5.87%)**
MN Non-Weighted Avg.	**$ 3.7946**		**$ 4.0254**		**$(0.2308)**	**(5.73%)**

Total system PGA-recovered and actual-incurred gas costs, as shown in Table G17, provide a comparison of the utilities' total system gas costs (demand and commodity). All six PGA systems under-recovered total gas costs during the reporting period, with Great Plains reporting the greatest under-recovery at 10.07 percent. MERC-NNG had the highest actual gas cost and MERC-Consolidated had the lowest actual gas cost.

Table G17a below shows the FYE18 increase or decrease in Minnesota non-weighted average total system gas costs over each of the previous years' rates. The figures below are nominal costs and are not adjusted for either inflation or weather conditions. Based on these data, during FYE18, the actual Minnesota non-weighted average total system cost of gas was $4.0254 per Mcf, representing an approximately three percent decrease from the FYE17 reporting period.

[112] The numbers reported in Table G17 are from the true-up filing submitted by each utility. The numbers and the detailed calculations used are contained in Department Attachments G12, G12a, and G16 through G18.

Table G17a: Non-Weighted Average Total System Gas Costs

Reporting Period	Rate ($/Dth)	Percent Increase (Decrease) vs. Prior Years
FYE18	$4.0254	
FYE17	$4.1520	(3%)
FYE16	$3.7072	9%
FYE15	$4.9621	(19%)
FYE14	$6.2268	(35%)
FYE13	$4.3327	(7%)
FYE12	$4.7892	(16%)
FYE11	$5.3295	(24%)
FYE10	$5.7062	(29%)
FYE09	$6.9548	(42%)
FYE08	$8.3613	(52%)
FYE07	$7.8131	(48%)
FYE06	$9.7936	(59%)
FYE05	$7.2930	(45%)
FYE04	$6.2626	(36%)
FYE03	$5.5635	(28%)
FYE02	$3.4941	15%
FYE01	$6.8382	(41%)
FYE00	$3.4529	17%
FYE99	$2.8627	41%

C. PER-UNIT MARGIN CHARGED TO RESIDENTIAL CUSTOMERS

Using data collected from information requests to each utility, the Department developed a list of the annual FYE18 per-unit margins charged by each utility, by pipeline system, to residential customers. Margins are approved by the Commission only at the time of a general rate case. Table G18 below presents the Department's summary of the per-unit margins as of June 30, 2018.

Table G18: FYE18
Actual Per-Unit Margin Rate by PGA System Charged to Residential Customers

Utility	System	Non-Gas Margin ($/Mcf)
Greater Minnesota[113]		$4.4433
Great Plains[114]		$2.5259
MERC[115]	CON	$2.5594
	NNG	$2.5579
CenterPoint Energy[116]		$2.2201
Xcel Gas[117]		$1.8591
MN Non-Weighted Avg.		**$2.6943**

As shown on Table G18, GMG has the highest residential non-gas margin. The Department notes that GMG is a relatively small company and, thus, its fixed costs are spread over fewer customers. The lowest residential non-gas margin is for Xcel Gas, which has not filed a rate case since 2009.

D. REVIEW OF GAS UTILITIES' PEAK-DAY DEMAND PROFILES

The Department used data from responses to Department information requests to develop a summary of each gas utility's peak-day demand profile, load factor, and reserve margin. Table G19 below presents a summary of this information.

[113] Greater Minnesota's most recent rate case was filed in Docket No. G022/GR-09-962. Greater Minnesota's non-gas margin rates were last changed as of November 1, 2010.
[114] Great Plains' non-gas margins changed effective January 1, 2016 pursuant to the Commission's approval of rates in Great Plains' most recent rate case, Docket No. G004/GR-15-879.
[115] MERC's non-gas margins changed effective January 1, 2016 pursuant to the Commission's approval of rates in MERC's most recent (relative to FYE18) rate case, Docket No. G011/GR-15-736. The rates approved in MERC's most recent rate case (Docket No. G011/GR-17-563) were not in effect in FYE18.
[116] CenterPoint Energy's non-gas margins changed effective October 1, 2015 pursuant to the Commission's approval of rates in CenterPoint Energy's most recent rate case, Docket No. G008/GR-15-424.
[117] Xcel Gas' non-gas margin rates were changed with the implementation of final rates on May 1, 2010 in rate case Docket No. G002/GR-09-1153.

Table G19:[118] FYE18
Firm Peak-Day Demand Profiles

Utility/System	Firm Design Day Demand (Mcf)	Firm Peak-Day Demand Deliverability (Mcf)	Annual Firm Throughput (Mcf)	Annual Firm Load Factor[119] %	Reserve Margin[120] %
Greater Minnesota[121]	11,896	12,609	1,140,351	30.16%	5.99%
Great Plains[122]	32,733	34,445	3,109,853	29.75%	5.23%
MERC					
Consolidated[123]	56,470	57,949	4,825,697	28.47%	2.62%
NNG[124]	273,842	266,317	24,507,563	28.70%	(2.75%)
CenterPoint Energy[125]	1,357,000	1,409,596	118,834,104	29.88%	3.88%
Xcel Gas[126]	730,147	776,298	72,593,858	35.92%	6.32%
MN Totals	**2,462,088**	**2,557,214**	**191,477,733**	**31.41%**[127]	**3.86%**[128]

As shown above, Minnesota's gas utilities exhibit a firm load factor between approximately 23.47 percent for MERC-Consolidated and approximately 35.92 percent for Xcel Gas. Also, the reserve-margin percentage, which includes each utility's contracted transportation and peak-shaving capacity, was approximately 3.86 percent during the reporting period. This level represents a 9.8 percent increase in the statewide reserve margin compared to the 3.52 percent figure reported in the last AAA Report. As shown in the table above, the reserve margins range from approximately (2.75) percent for MERC-NNG[129] to approximately 6.32 percent for Xcel Gas.

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118 See Department Attachment G20.
119 The load factor equals the daily average firm throughput (annual firm throughput [from Table G19] divided by 365) divided by actual firm peak-day demand (from Table G20).
120 The reserve margin equals (using values from Table G19) the firm peak-day demand entitlement minus firm design-day demand divided by firm design-day demand.
121 Regarding the 2017-2018 period, the reserve margin is further discussed in Docket No. G022/M-17-399.
122 Regarding the 2017-2018 period, the reserve margin is discussed further in Docket No. G004/M-17-521.
123 Regarding the 2017-2018 period, the reserve margin is further discussed in Docket No. G011/M-17-587.
124 Regarding the 2017-2018 period, the reserve margin is discussed further in Docket No. G011/M-17-588.
125 Regarding the 2017-2018 period, the reserve margin is further discussed in Docket No. G008/M-17-533.
126 Regarding the 2017-2018 period, the reserve margin is further discussed in Docket No. G002/M-17-586.
127 This percent represents the weighted average of Minnesota gas utilities' load factors.
128 This percent represents the weighted average of Minnesota gas utilities' reserve margins.
129 The Department monitored MERC-NNG's very low reserve margin in Docket No. G011/M-16-650. Additionally, the heating season passed with no service issues.

The Department supports the continuation of the Commission's requirement that the reserve margins be included in the annual automatic adjustment report since the information is useful for comparison purposes. However, the Department conducted no analysis of the reserve margins in the current filing, but only reported the information in a standardized way. Each utility's reserve margin is analyzed by the Department, and approved by the Commission, in conjunction with that utility's annual demand-entitlement filing.

The Department also used data from responses to information requests to compare each gas utility's firm peak-day demand deliverability to its actual firm peak-day use. Table G20 below presents a summary of this information.

Table G20: FYE18
Comparison of Firm Peak-Day Demand Usage

Utility/System	Firm Peak Day Demand Deliverability[130] (Mcf)	Actual Firm Peak Day Usage (Mcf)	Actual Firm Requirement (%)	Actual Peak Date
Greater Minnesota	12,609	10,360	82%	12/31/17
Great Plains	34,445	28,641	83%	1/4/18
MERC				
Consolidated	57,949	46,438	80%	12/30/17
NNG	266,317	233,945	88%	12/31/17
CenterPoint Energy	1,409,596	1,089,622	77%	12/31/17
Xcel Gas	776,298	553,667	71%	12/26/17
MN Totals	**2,557,214**	**1,962,673**	**77%**	

As Table G20 reflects, all of the regulated gas utilities in Minnesota were able to meet their actual firm peak-day FYE18 usage within their proposed demand entitlement levels. The peak day for Minnesota regulated gas utilities occurred on multiple days during the 2017-2018 heating season as indicated above. The utilities had an aggregate peak-day usage, or sendout, of 1,962,673 Mcf. The companies planned for an aggregate peak of 2,557,214 Mcf, implying that approximately 77 percent of the planned peak-day sendout was actually used during FYE18. The FYE18 aggregate peak represents an eight percent increase in the peak-day usage compared to the previous heating season.

[130] Demand deliverability includes contracted firm transportation, on-line storage capacity, and the maximum daily injection capacity of peak-shaving facilities.

E. DAILY DELIVERY VARIANCE CHARGES

As mentioned previously, in choosing a reasonable balance of pipeline services, a utility will determine the amount of entitlements and other related pipeline services required to meet the needs of its firm customers reliably. Each utility is required to "nominate" (tell the pipeline) the daily amount of its expected gas use within a certain degree of accuracy. These nominations, and a utility's overall blend of services, determine the utility's ability to provide reliable service on a daily basis, especially during extreme weather fluctuations. In general, when a utility does not nominate its daily amounts (or cannot schedule the amount of capacity needed because of portfolio limitations) within a given percentage of the firm entitlement level actually used, it faces additional pipeline charges (or penalties).

Interstate pipelines (*e.g.,* Northern Natural Gas Co., Viking Gas Transmission Co.) impose balancing penalties on their shippers, such as Minnesota utilities, when these shippers do not nominate their daily capacity amounts within a given percentage of the actual entitlement level used. On NNG's system, these charges (or penalties) are known as positive, negative, or punitive daily delivery variance charges (DDVCs). The current Northern DDVC cost structure for gas taken in excess of nominated levels is as follows:[131]

Table G21: NNG's DDVC Structure[132]

Type	Current Charge
Negative DDVC	0.40[133]
Positive DDVC	$1.00[134]
Punitive DDVC	5 x SMS Rate[135]
Positive/Critical DDVC:	
- First 2%	$15.00
- Next 3 %	$22.00
Punitive/Critical DDVC:	
- Level I (5 - 10% above)	$56.50
- Level II (more than 10% above)	$113.00

[131] See Northern Natural Gas Company's FERC Gas Tariff, Vol. No. 1, Sheet No. 53.

[132] System Overrun Limitation (SOL) and System Underrun Limitation (SUL) are parameters or boundaries that limit the use of System Management Service (SMS) service on days for which Northern's system integrity is threatened and System Balancing Agreement (SBA) provisions are not adequate in maintaining pipeline operations. See Northern Natural Gas' Tariff Sheet 292.

[133] On non-SOL/SUL/Critical days, the rate is the maximum November-March Market Area TI rate during the November-March period and the maximum April-October TI rate during the April-October period.

[134] *Id.*

[135] *Id.*

The Commission previously ordered each regulated gas utility to provide a listing of the pipeline penalties each utility incurred.[136] Table G22 below provides a summary of the pipeline penalties incurred during the FYE18 reporting period.

Table G22:[137] FYE18
Daily Delivery Variance Charges (DDVC)[138]
Incurred By Utility

Utility/System	**DDVC (Mcf)**	**DDVC ($)**	**Total Gas Costs ($)**	**Percent of Total Costs Represented By Penalties (%)**
Greater Minnesota	12,816	$5,426	$5,565,282	0.0975%
Great Plains	40,338	$4,934	$16,897,064	0.0292%
MERC				
Consolidated	0	$0	$20,787,490	0.0000%
NNG	690	$242	$132,619,114	0.0002%
CenterPoint Energy	77,206	$38,908	$572,097,915	0.0068%
Xcel Gas[139]	178,100	$45,831	$274,859,909	0.0167%
MN Totals	**309,420**	**$95,341**	**$1,022,826,774**	**0.0093%**

As shown above, the penalties incurred by the gas utilities range from $0 MERC-CON to $45,831 for Xcel Gas. On a percentage basis, the penalties range from 0.0000 percent MERC-Consolidated to approximately 0.0975 percent for GMG.

In their responses to the Department's Information Request No. 7, utilities identified the amount of each type of DDVC imposed. Table G23 below provides a summary of the type of DDVC penalty incurred during the FYE18 reporting period.

136 See Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1171, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-93-1093, and G012/M-93-1251.
137 Table G22 summarizes the data provided in Department Attachment G14.
138 Viking's charges are called overrun charges rather than DDVC's. Further, Viking does not have a punitive charge category.
139 Xcel's charges include DDVCs, as well as overrun charges on the Viking and Williston Basin Interstate Pipeline (WBI) systems.

Table G23:[140] FYE18
Amount of DDVCs Incurred by Type

Utility/System	Positive & Negative	Punitive	Total	Percent of Total MN DDVCs
Greater Minnesota	$4,206	$1,220	$5,426	5.69%
Great Plains	$4,934	$0	$4,934	5.18%
MERC				
Consolidated	$0	$0	$0	0.00%
NNG	$242	$0	$242	0.25%
CenterPoint Energy	$38,908	$0	$38,908	40.81%
Xcel Gas	$45,831	$0	$45,831	48.07%
MN Totals	**$94,121**	**$1,220**	**$95,341**	**100%**

As shown above, all Minnesota regulated gas utilities except MERC-Consolidated incurred some type of DDVC during the FYE18. Total DDVC penalties for all gas utilities increased by $16,137 (from $79,204 for FYE17 to $95,341 for FYE18), or approximately 20 percent, from the amount reported in FYE17. Only GMG experienced punitive penalties during FYE18. The Department notes that NNG's Penalty Charge Credits received by each utility, and included in the true ups for FYE18, are separately shown below in Table G25a.

The Department recognizes that nominations require careful analysis and consistent forecasting methods. Major decisions regarding nominations must be made by 1 p.m. the day before the gas day.[141] An intraday nomination is a nomination electronically submitted after the initial nomination. Intraday nominations may be used to nominate new market or supply and can be used to request increases or decreases in total flow, changes to receipt points, or changes in delivery points of scheduled gas.[142] There are three opportunities to make intraday nominations:

- by 10:00 a.m. on the gas day (to be effective at 2:00 p.m. on the gas day);
- by 2:30 p.m. on the gas day (to be effective at 6:00 p.m. on that day); and
- by 7:00 p.m. on the gas day (to be effective at 10:00 p.m. on that day).

The Department also recognizes that a certain level of positive and negative DDVCs is a natural result of daily weather fluctuation, advance nomination decisions, and limited opportunities to make intraday nominations. Moreover, a utility's ability to make appropriate intraday

[140] Table G23 summarizes the data provided in Department Attachment G14.
[141] See Northern Natural Gas Company's FERC Gas Tariff, Sixth Revised Vol. No. 1, Third Revised Sheet No. 257, issued February 1, 2016.
[142] *Id*. Northern reserves the right to limit acceptance of an intraday nomination on a non-discriminatory basis if system integrity will be placed in jeopardy.

nominations can be limited by the information the utility has from customers about expected gas use on a particular day. Nevertheless, the Department encourages utilities to continue to use the various available tools to minimize DDVC penalties, such as using pipeline storage facilities and peak-shaving plants or curtailing interruptible customers as discussed further below.

F. REVENUE FROM CURTAILMENT AND BALANCING PENALTIES IMPOSED BY REGULATED MINNESOTA GAS UTILITIES

As discussed above in Section III, part E, utilities must nominate and use interstate pipeline capacity in a responsible manner or face penalties. Thus, utilities established guidelines for responsible system use by transportation and interruptible customers, with penalties for those customers who do not use the gas system in a responsible manner.

All of Minnesota's regulated gas utilities have received Commission approval to implement a number of changes in tariff language that:

- add several special conditions on nominations, balancing, and gas use during curtailments;
- introduce penalties to discourage customers from using gas when service is interrupted; and
- encourage customers to nominate and balance gas supplies responsibly.

Curtailment penalties and balancing penalties are discussed below.

1. Curtailment Penalties

Curtailment penalties are fines imposed by regulated Minnesota gas utilities on interruptible customers who fail to curtail or interrupt their use of natural gas supplies when requested to do so by the utility. It is important that interruptible customers who do not use the gas system in a responsible manner be held financially accountable. When interruptible customers choose to take service under an interruptible tariff, they accept the potential of curtailment in return for lower prices than are charged firm customers. That is, interruptible customers do not pay for demand/capacity costs. If an interruptible customer fails to curtail when notified, the utility (not the individual interruptible customer) may face pipeline penalties too, which, in turn, would raise rates to all customers. Conceptually, failure to curtail also could jeopardize reliable gas service to firm customers. Therefore, the Commission approved utility tariffs under which, if interruptible customers fail to respond to curtailment notices, they are charged curtailment penalties.

Below is a summary of the revenue from curtailment penalties imposed on interruptible customers during FYE18.

Table G24:[143] FYE18
Revenue from Curtailment Penalties

Utility/System	Total Penalties ($)	Percent of Total Penalties (%)	Total Costs Incurred[144] ($)	Penalties as a Percent of Total Costs Incurred (%)
Greater Minnesota	$0	0.00%	$5,565,282	0.0000%
Great Plains	$0	0.00%	$16,897,064	0.0000%
MERC				
Consolidated	$0	0.00%	$20,787,490	0.0000%
NNG	$1,341	0.11%	$132,619,114	0.0010%
CenterPoint Energy	$0	0.00%	$572,097,915	0.0000%
Xcel Gas	$1,266,073	99.89%	$274,859,909	0.4606%
MN Total	**$1,267,414**	**100.00%**	**$1,022,826,774**	**0.1239%**

As shown above, two utilities imposed curtailment penalties on interruptible (or dual-fuel) customers. Penalties as a percent of total costs ranged from 0 percent (multiple utilities) to 0.4606 percent for Xcel Gas. The Department notes that revenues from curtailment penalties identified above are to be returned to all sales customers as a credit to demand cost in the annual true-ups.

For the reporting period, the total amount of curtailment penalties was $1,267,414. This amount is an increase of $1,199,942 from the FYE17 figure of $67,472. The increase in curtailment penalty revenue versus FYE17 is due almost entirely to Xcel Gas. In FYE17, Xcel Gas had one partial priority curtailment day; in FYE18, Xcel Gas called six full priority days and one partial priority day.

This increase in unauthorized use on Xcel Gas's system is concerning for three reasons. First, despite the colder-than-normal weather, all of the regulated utilities except for Xcel Gas were able to manage their unauthorized gas use down to or near zero. Second, because Minnesota experienced a polar vortex during the 2018-2019 heating season that brought record-setting cold to all areas of the state, the Department assumes that unauthorized gas use increased significantly during 2018-2019. Finally, during the 2018-2019 heating season, Xcel Gas lost enough pressure in its distribution lines to have to interrupt service to over 150 customers.[145]

[143] The penalties listed in Table G24 are taken from the utilities' responses to Department Information Request No. 8. Responses are available upon request.
[144] The figures listed in the column entitled "Total Costs Incurred" in Table G24 are taken from the gas utilities' true-up filings. Total costs incurred include both demand and commodity costs.
[145] Docket No. E,G999/CI-19-160 *In the Matter of a Commission Inquiry into the Impact of Severe Weather in January and February 2019 on Utility Operations and Service*.

Below is a table summarizing the total unauthorized dekatherms used by Xcel Gas's interruptible customers since the polar vortex in FYE14.

Table G24a
Xcel Gas Historical Unauthorized Gas Volumes

Heating Season	Unauthorized Dkt
2013-2014	126,589.68
2014-2015	19,141.63
2015-2016	-
2016-2017	126.11
2017-2018	28,915.68
2018-2019 (Polar Vortex event only)[146]	17,688.93

Xcel Gas's unauthorized gas used has dropped significantly from 126,589.68 Dkt in FYE14 to 28,915.68 Dkt in FYE18, but in comparison to the other regulated utilities, there appears to be room for further improvement.

Normally, the Department would not request data ahead of the required September 1 annual filing date, but this situation warrants further investigation as soon as possible. The Department requests that Xcel Gas provide, in its *Reply Comments*, a list of unauthorized gas use during the 2018-2019 heating season in the same detail as its compliance filing submitted in this instant docket on March 22, 2019. The Department also requests that Xcel include a discussion detailing all barriers to further reducing unauthorized usage, and suggesting possible solutions. .

2. Balancing Penalties

Balancing penalties are fines imposed by regulated Minnesota utilities on transportation customers who fail to nominate the daily amount of expected gas use within a certain degree of accuracy. For the same reasons cited above for interruptible customers, transportation customers must be held financially accountable if they do not use the gas system in a responsible manner. If a transportation customer fails to nominate correctly, the utility (not the individual transportation customer)[147] may face pipeline penalties, which, all else being equal, in turn raises rates to all customers. Northern considers transportation gas as "the first through the meter" (*i.e.*, the pipeline considers transportation gas to be in balance, and shifts

[146] Page 11 of Xcel Gas's *Comments* filed on April 15, 2019 in Docket No. E,G999/CI-19-160.
[147] This situation is generally the case except for transportation customers who sign "End-User Balancing Agreements" with the interstate pipeline. In such cases, the interstate pipeline directly monitors gas use and directly bills the transportation customer any imbalance charges.

any remaining imbalance to sales customers). To avoid having sales customers subsidize transportation customers, utilities impose balancing penalties on specific transportation customers for their imbalances and credit other customers with the resulting revenues.

Table G25 below contains a summary of the revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers during FYE18.

Table G25:[148] FYE18
Revenue from Balancing Penalties

Utility/System	Balancing Penalty Rev. ($)	Penalty Rev. as a Percent of Total Penalties (%)	Total Gas Costs Incurred[149] ($)	Penalty Rev. as a Percent of Total Costs Incurred (%)
Greater Minnesota	$2,135	0.17%	$5,565,282	0.0384%
Great Plains	$71,725	5.61%	$16,897,064	0.4245%
MERC				
Consolidated	$47,573	3.72%	$20,787,490	0.2289%
NNG	$160,858	12.59%	$132,619,114	0.1213%
CenterPoint Energy	$895,661	70.08%	$572,097,915	0.1566%
Xcel Gas	$100,119	7.83%	$274,859,909	0.0364%
MN Total	**$1,278,071**	**100.00%**	**$1,022,826,774**	**0.1250%**

As shown above, the revenue from balancing penalties imposed on transportation customers by gas utilities ranges from $2,135 reported revenues (GMG) to $895,661 (CenterPoint Energy). The percent of total costs ranges from 0.0364 percent (Xcel Gas) to 0.4245 percent (Great Plains). The total amount of balancing penalties was $1,278,071, which is $29,782 more than last year's amount of $1,248,289.[150] In addition to the above revenue from balancing penalties, NNG pays an annual Penalty Charge Credit to all shippers on its system. The credits reported as received by each utility for FYE18 were as follows:

[148] The data provided in Table G25 is taken from the response to Department Information Request No. 9.
[149] The figures listed in the column entitled "Total Costs Incurred" in Table G25 are taken from the gas utilities' Annual True-Up filings. Total costs incurred include demand and commodity costs.
[150] This amount is corrected from FYE17. In FYE17, MERC reported balancing revenue of $0 and $10,350 for MERC-Consolidated and MERC-NNG, respectively. In Department Information Request No. 24 in this instant docket, the Department requested an explanation for why the reported balancing revenue increased so much from FYE17 to FYE18. MERC's response indicated that its reporting in FYE17 was incorrect; the amounts that should have been reported are $46,173 and $154,231 for MERC-Consolidated and MERC-NNG, respectively.

Table G25a:[151] FYE18 NNG Penalty Charge Credits by Utility

Greater Minnesota	$1,140
Great Plains	$0
MERC	
Consolidated	$0
NNG	$242
CenterPoint Energy	$204,267
Xcel Gas	$92,218
MN Total	**$297,867**

G. PEAK-DAY PIPELINE TRANSPORTATION SOURCES

In its analysis of gas supply peak-day reliability, the Department considered two factors: (1) the various pipeline companies that deliver gas to Minnesota gas utilities, and (2) the number of suppliers currently serving each gas utility (discussed in the next section). Table G26 below shows the variety and contribution of pipelines supplying peak-day firm transportation capacity to Minnesota utilities. The peak-day capacity for FYE18 was 2,683,496 Mcf, which is an increase of approximately 2.94 percent, or 76,668 Mcf, from FYE17.

Table G26:[152] FYE18
Summary of Utilities' Gas Supply Transportation Sources
Total Minnesota Peak Quantity

Pipeline	Peak-Day Quantity (Mcf per day)	Peak -Day Quantity Percent of Total
Northern Natural Gas Co.	1,864,202	69.47%
Viking Gas Transmission Co.	199,975	7.45%
Great Lakes Pipeline Co.	31,358	1.17%
Other Pipelines	61,961	2.31%
Peak Shaving & Online Storage	526,000	19.60%
MN TOTAL	**2,683,496**	**100.00%**

The percentage of peak-day capacity provided by each of the above sources remains similar from the amounts in FYE17. Northern provides by far the greatest amount of peak-day capacity to Minnesota utilities, with approximately 69.47 percent of the total peak-day capacity. Depending on the specific situation of each utility, the number of different pipelines transporting gas to a particular utility for Minnesota ratepayers ranges from one to five. While

[151] The data provided in Table G25a is taken from the response to Department Information Request No. 9.
[152] The data provided in Table G26 is taken from the response to Department Information Request No. 4.

some utilities may have greater options than others in their ability to decrease costs by choice of pipeline sources, pipeline differentiation does not appear to impact service reliability.

H. VARIETY OF GAS SUPPLIERS

The number of gas suppliers used during the heating season varies by utility, ranging from 0 to 72 for long-term firm supplies, 1 to 72 for firm spot supplies, and from 0 to 5 for interruptible sources. Table G27 below shows the number of long-term firm, firm spot, and interruptible suppliers used by each utility during the 2017-2018 heating season.

Table G27:[153] FYE18
Number of Suppliers

Utility	Firm Long-Term Suppliers	Firm Spot Suppliers	Interruptible Suppliers
Greater Minnesota	0	5	5
Great Plains	2	1	3
MERC[154]	72	72	0
CenterPoint	15	9	0
Xcel Gas	21	24	0

In choosing suppliers, all utilities reported that they carefully review the history and performance of potential gas suppliers. Among the criteria considered are reliability, stability, flexibility, reputation, financial condition, communications quality, price, and non-performance penalties. Most of the utilities then proceed on a trial-and-error basis with a selected supplier, assessing whether the supplier may be relied upon for firm sales requirements. After the utilities are satisfied with the supplier's performance, they sign contracts with particular suppliers based on the lowest bids.

I. CAPACITY RELEASE

Capacity release allows gas utilities with transportation entitlements on a pipeline to relinquish unused and unnecessary capacity for variable periods of time and under various conditions. The Commission typically requires utilities to return to ratepayers all revenues from capacity-release transactions through the annual true-up process.[155] Below is a summary of capacity releases and the associated revenues returned to ratepayers during the true-up period.

[153] Table G27 is based on the utilities' responses to Department Information Request No. 4.
[154] MERC provided the number of suppliers from which they can purchase gas. MERC also stated that no interruptible gas is purchased.
[155] See Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1219, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-95-182, and G012/M-93-1251.

Table G28:[156] FYE18
Capacity Release

Utility/System	Capacity Release (Mcf)	Capacity Release ($)	Revenue Per Mcf ($)	Total Gas Costs Incurred[157] ($)	Revenue as a Percent of Total Gas Costs (%)
Greater Minnesota	126,023	$38,504	$0.3055	$5,565,282	0.6919%
Great Plains	-	-	$0.0000	$16,897,064	0.0000%
MERC					
Consolidated	6,138,310	$414,618	$0.0675	$20,787,490	1.9946%
NNG	11,882,614	$1,012,012	$0.0852	$132,619,114	0.7631%
CenterPoint Energy	4,860,000	$139,884	$0.0288	$572,097,915	0.0245%
Xcel Gas	3,987,344	$632,132	$0.1585	$274,859,909	0.2300%
MN Total	**26,994,291**	**$2,237,150**	**$0.0829**	**$1,022,826,774**	**0.2187%**

Table G28 shows the large diversity in Minnesota for capacity-release transactions, capacity portfolios, and individual situations of each gas utility. The revenue from capacity release ranges from $0 for Great Plains to $1,012,012 for MERC-NNG. As a percent of total gas costs, the capacity-release revenues ranged from 0.000 percent for Great Plains to 1.9946 percent for MERC-Consolidated. Utilities returned a total of $2,237,150 to ratepayers in the true-ups in FYE18 compared to the FYE17 amount of $3,377,810. The total volumetric capacity-release figures decreased from 29,455,563 Mcf to 26,994,291 Mcf between the FYE17 and FYE18 reporting periods. The decrease in capacity release volume correlates with Table G20, as the actual firm capacity requirement was 77 percent of total capacity on the peak day in FYE18, compared to 73 percent in FYE17.

J. ANNUAL AUDITOR REPORTS

All regulated utilities are required by Minnesota Rule 7825.2820 to submit an independent auditor's report by September 1 of each year that evaluates the accounting for automatic adjustments for the prior year. Regarding Commission-ordered audit requirements, beginning with the FYE99 AAA report, the Commission has annually required that the gas utilities meet with their independent auditors prior to the auditors' examinations concerning the companies'

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[156] The data listed in Table G28 is based on the utilities' responses to Department Information Request No. 6.
[157] The data listed in the column entitled "Total Cost Incurred" is taken from the gas utilities' AAA filings. Total costs incurred include demand and commodity costs.

AAA reports, to review audit procedures and Minnesota Rule 7825.2820.[158] Additionally, the Commission requires gas utilities to direct their independent auditors to include, as one of their procedures, an examination of any significant variations between purchased volumes (per invoices) and sales volumes per the general ledger sales journal.[159] The Commission also requires all gas utilities to continue to have independent auditors verify in writing in their AAA reports that the actual amounts included in the true-up calculations agree with the utilities' accounting books and records.[160]

All gas utilities submitted auditor's reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes that there were no exceptions indicated by the auditors.

K. LOST-AND-UNACCOUNTED-FOR GAS

Ordering Paragraph 5 in the Commission's April 7, 2011 *Order* in the FYE10 AAA Report requested that the Department continue to develop and report a summary and comparison of each regulated natural gas utility's lost-and-unaccounted-for (LUF) gas percentages and to include a table or attachment that includes the data used in the calculations of the LUF percentages.

Using the formula from the U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration's Form 7100.1-1 to calculate the LUF percentages,[161] the Department developed a comparison of LUF gas by utility. Table G29 below presents the Department's summary of LUF gas percentages for the period July 1, 2017 to June 30, 2018 for Minnesota jurisdictional volumes.

[158] See Docket Nos. G,E999/AA-98-1130, G,E999/AA-99-1095, G,E999/AA-00-1027, G,E999/AA-01-838, G,E999/AA-02-950, and G,E999/AA-03-1264.
[159] See Docket No. G,E999/AA-97-1212.
[160] See Docket No. G,E999/AA-96-940.
[161] The formula is as follows: [(purchased gas + produced gas) minus (customer use + utility use + appropriate adjustments)] divided by (purchased gas + produced gas) equals percent LUF.

**Table G29:[162] FYE18
Lost-and-Unaccounted-For Gas**

Utility/System	Revenue as a Percent of Total Gas Costs (%)
Greater Minnesota	0.14%
Great Plains	1.28%
MERC	
Consolidated	(0.84)%
NNG	(1.40)%
CenterPoint Energy	1.86%
Xcel Gas	1.88%
MN Weighted Avg.	**1.41%**

A negative LUF number means that a utility, in effect, "found" gas. As shown in Table G29 above, MERC-NNG and MERC-Consolidated reported negative LUF during the reporting period. As shown in Table G29, the LUF gas ranged from a negative 1.40 percent for MERC-NNG to a positive 1.88 percent for Xcel Gas. The Minnesota weighted average was 1.41 percent.

Except for MERC and Xcel Gas, as discussed below, the Department concludes that FYE18 LUF percentages are reasonable.

1. MERC

MERC has had a long, and well-documented, history of negative LUF,[163] however the Company has been unable to pinpoint a cause for such consistent and significant negative LUF. In its February 27, 2019 *Order* in Docket No. G999/AA-17-493, the Commission required MERC to submit, within 30 days of the *Order*, a compliance filing outlining a plan to investigate its lost and unaccounted for gas. The *Order* further requires MERC file a report on the results of that investigation with the Company's FYE19 AAA Report to be filed by September 3, 2019.

MERC submitted its compliance on March 26, 2019. In its filing, MERC stated,

> MERC has previously undertaken steps to investigate the negative LUF trend and, while the Company identified some minor errors in the past, the Company has not found anything that consistently pointed to billing errors, metering errors, or purchased gas

[162] See Attachment G19 for detailed calculations.
[163] Please see LUF discussions in the Department's Reports in Docket Nos. G999/AA-09-896 and G999/AA-14-580.

> accounting methodology errors. While the Company plans to undertake the additional investigation as outlined in this Compliance Filing, it is not certain that any specific explanation will be identified as a result of the investigation. Notably, the negative LUF trend has occurred only on the NNG PGA while MERC's Consolidated PGA has varied between positive and negative LUF year-to-year. As a result, MERC intends to focus its further investigation on the NNG PGA.

The Department does not agree with MERC's assessment to perform its investigation only for its NNG PGA. The Commission did not differentiate between the two PGA systems in its *Order*, therefore, the Department recommends that MERC conduct its investigation on both its NNG and Consolidated PGA systems.

As for MERC's proposed plan, the Department does not note any specific issues or concerns and looks forward to reviewing the findings in the FYE19 AAA Report.

2. Xcel Gas

At the April 26, 2018 Commission Agenda meeting, the Commission observed that Xcel Gas's LUF gas volumes were higher than the other regulated utilities over the previous several years.

Xcel Gas agreed and had its internal audit department investigate the issue, which identified five items to note as part of the unaccounted for gas volumes:[164]

- Fuel losses incurred in conjunction with storage injections were not separately identified in the Company's response to DOC Information Request 16 (IR 16) and thus would be in the unaccounted for gas volume total.
- Fuel used in the operations associated with liquefying and vaporizing liquefied natural gas have not been separately identified in IR 16, and would be included in the unaccounted for total.
- Third-party cash out volumes are not quantified in the Company's reconciliation of purchase and sale volumes in IR 16.
- Metered gas volumes that are not billed because they are associated with vacant premises and/or the owner is unknown are included in the total unaccounted for gas.
- The Company's investigation also identified an allocation issue regarding gas volumes used at the High Bridge plant. High Bridge is one of Xcel Energy's natural-gas powered electric generation

[164] Xcel Gas's Annual Report, Attachment G, pages 2-3.

> units, and is a natural gas transport customer of the LDC. As part of the end-user allocation agreement between High Bridge and LDC, the LDC communicates to Northern Natural Gas (NNG) the volumes used by High Bridge. NNG uses these volumes to allocate costs between the LDC and the electric utility. The High Bridge volumes were being reported from SCADA measurements instead of the MV90 metering (MV90 is billing quality data, SCADA is not). The High Bridge volumes have been understated to NNG over the last several years, and thus the plant has used more gas than they have brought on to the system. The table below shows the volume impact on Lost and Unaccounted for gas of this issue.
>
> **Adjustment to Lost and Unaccounted for Total**
>
> | | MN | MN Adj | Diff |
> |---|---|---|---|
> | FYE14 | 1.30% | 1.14% | -0.16% |
> | FYE15 | 2.46% | 2.08% | -0.37% |
> | FYE16 | 2.72% | 2.11% | -0.61% |
> | FYE17 | 2.52% | 2.14% | -0.38% |
>
> The Company is making a one-time adjustment to true-up the difference between what the plant burned versus the gas the plant delivered to the system. In order to value this gas the LDC used its tariff based cash-out mechanism. The total system cost impact is estimated to be approximately $6 million ($4.2 million for these four years, and $1.8 million for the current 2017-18 gas year), based on the over/undertake cash-out mechanism in our transportation tariffs. We have included a total system credit of $6 million ($5.2 million for Minnesota) in the 2017-18 gas true-up filing, with these true-up factors applied to customer bills over the next 12 months. We intend to allocate this adjustment to electric customers through the monthly FCAs over a similar one-year period.

To summarize, Xcel Gas incorrectly reported to NNG the amount of gas used by Xcel Gas' transportation customer, Xcel Electric's High Bridge generating plant, thus Xcel Gas has been charged for more gas than was actually used, and Xcel Electric has been charged less.

As an initial matter, the Department notes that, while Minnesota Rule 7825.2920, subp. 2 addresses errors made in the automatic adjustment of charges, the High Bridge situation was an error in the amount billed a transportation customer of Xcel Gas. Minnesota Rule 7820.4000 addresses natural gas customer billing errors (Minnesota Rule 7820.3800 applies to electric customer billing errors). However, Xcel Gas' true-up filing includes a credit to all customers; the record does not indicate whether the High Bridge plant or Xcel Electric's customers are being or will be surcharged a similar amount. Given the sparse record, it is not clear to the Department whether Minnesota Rule 7825.2920 or 7820.4000 applies. The Department requests that Xcel provide in *Reply Comments* its analysis of which rule applies. In addition, the Department requests that Xcel Gas provide the amounts that should be surcharged and/or refunded associated with each year in which the SCADA readings were erroneously provided to NNG assuming Minnesota Rule 7825.2920 applies, and the same information assuming Minnesota Rules 7820.3800/7820.4000 apply.

The Department notes that the Company included a $3,669,040 "High Bridge Adjustment" in its True-Up filing without explanation or reference to the explanation contained in Attachment G to its AAA Report.[165] The amount of $3,669,040 shown as a credit to all customer classes in Schedule A of Xcel Gas' True-Up does not tie to the $5.2 million mentioned in the narrative of Attachment G, page 3 of Xcel's Gas's AAA Report. The Department recommends that in *Reply Comments*, Xcel Gas provide the detailed calculations supporting its High Bridge adjustment, including a reconciliation of the $3.7 million and $5.2 million totals provided in the Company's filings.

Since this metering error appears to impact Xcel Electric's fuel clause adjustment calculation, the Department recommends that Xcel file a supplemental filing in Docket No. E999/AA-18-373 as soon as possible, so the High Bridge issue can be addressed in *Reply* and *Response Comments* in that docket. The Department recommends that the filing contain, at a minimum, a discussion of the allocation error, the underlying calculations and reconciliations for the adjustment(s) broken down by customer class, and a legal analysis as to whether Minnesota Rule 7825.2920 applies to any adjustment proposed or needed to Xcel Electric's fuel clause adjustment or whether Minnesota Rule 7820.3800 applies.

Despite the extensive issues created by Xcel Gas regarding this matter, the Department is encouraged to see that the Company was able to find causes for its inflated LUF percentages. The Department concludes that Xcel Gas's LUF percentage for FYE18 is reasonable.

In order to ensure clarity in future records, the Department recommends that the Commission require all regulated gas utilities to demonstrate that any prior-period adjustment made in an Annual True-Up is not subject to the Billing Error Rule.[166]

[165] Xcel Electric's AAA Report does not specifically identify a "High Bridge Adjustment."

[166] Minnesota Rules 7820.3800 and 7820.4000 state the following regarding overcharges, "If the recalculated bills indicate that more than $1 is due an existing customer or $2 is due a person no longer a customer of the utility, the full amount of the calculated difference between the amount paid and the recalculated shall be refunded to the customer." Regarding undercharges, the Rules state, "If the recalculated bills indicate that the amount due the utility exceeds $10, the utility may bill the customer for the amount due."

L. REPORTING OF CONTRACTOR MAIN STRIKES AND METER TESTING

In its October 11, 2012, *Order Accepting Progress Reports and Meter Testing Plans* in Docket No. G999/AA-10-885, the Commission required all gas utility companies to file, as part of their annual AAA reports, a schedule reflecting the contractor main strikes during the corresponding annual period billings to at-fault contractors. The Commission specifically required that the schedules reflect the date, party involved, repair cost amount, and gas lost amount for each incident. Additionally, the Commission required the utilities to file any updates regarding meter testing within an annual period in their AAA reports starting in 2012.

1. Contractor Main Strikes Reports

Regarding contractor main strikes reports, all of the gas utilities filed the required information.[167] The Department reviewed the reports. In its FYE14 AAA Report, the Department stated that the reports would be more meaningful if the total gas costs charged for main strikes during the period are reconciled to the amount in the true-up and also if the reports provide the allocation of the gas costs credited to each customer class.

The Department requests that MERC and CenterPoint provide in *Reply Comments* a discussion of the treatment of its gas losses due to damages (*i.e.*, how the cost of gas lost is collected from third parties and credited back to Firm customers) for each PGA system.

Additionally, in future AAA Reports, the Department again requests that MERC provide totals for Schedule Q.

Otherwise, all of the utilities totaled the gas cost charged for main strikes and indicated how the contractor main strike revenue was treated in the FYE18 true up, therefore complying with the requirement.

More specifically, the Department notes that the same third party was responsible for the most strikes by any one party on both the MERC-NNG and CenterPoint Energy systems.[168] This third party caused 19 strikes on MERC-NNG's system and 34 strikes on CenterPoint Energy's system. These strikes on MERC's system accounted for 37 percent of total dekatherms lost in 2017 and eight percent of dekatherms lost in FYE18 on CPE's system. The Department requests that MERC-NNG and CenterPoint provide a discussion in *Reply Comments* regarding this third party, including but not limited to whether this level of strikes is typical and any action the utilities have taken to reduce strikes caused by this party.

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[167] See GMG's AAA Report, page 5, Great Plains' AAA Report, Page 5 and Exhibit C, MERC's AAA Reports, Schedule Q, CenterPoint Energy's AAA Report, Exhibit 9 and Xcel Gas' AAA Report, Attachment G, Schedule 7.

[168] The Department does not name this party in this Report, as information on individual customers, contractors, vendors, etc. are considered Trade Secret by both MERC and CenterPoint Energy.

2. Meter Testing Updates

Regarding meter testing updates, all of the gas utilities filed the required information with their AAA Reports.

GMG stated:

> GMG's meter testing program has not changed since its comprehensive meter testing plan was approved by the Commission. GMG continues to sample and test at least 20 meters annually. No material problems have been identified during meter testing that demonstrate any trends in meter accuracy or systemic bias by type or size of meter.

Great Plains explained that there were no changes to its Gas Distribution Standards, Section 7 during the 2017-2018 reporting period.[169]

MERC stated that for both of its PGA systems:

> During the time period of January 1, 2017 through December 31, 2017, MERC tested 8,415 meters as part of its meter testing program. Of those meters tested, 7,876 (93.6%) tested between 98% and 102% accurate, 452 meters (5.4%) tested greater than 102% accurate, 85 meters (1.0%) tested less 98% accurate and 2 meters (0%) had no test due to the meter being damaged.[170]

CenterPoint Energy stated:[171]

> CenterPoint Energy continued its meter testing and management program in 2017. Meter samples and tests are conducted over a two-year period and the results of current interval 2017-2018 have been reviewed. All meter lots evaluated passed the accuracy expectations.
>
> During 2017 the Company exchanged 7,125 'failed' meters, and year to date through June 2018, 3,196 meters have been exchanged. Per the meter management program, the work plan for 2019 is set to target an additional 1,600 meters to be

[169] Great Plains' AAA Report, page 5.
[170] MERC-NNG's AAA Report, page 8 and MERC-CON's AAA Report, page 4.
[171] CenterPoint Energy's AAA Report, page 25.

> exchanged, as previously identified meter groups requiring attention. This work is ahead of the overall replacement plan.

Xcel Gas stated that "There were no changes regarding meter testing within the annual reporting period of July 1, 2017 and June 30, 2018."[172]

The Department concludes that the utilities complied with the Commission's Order.

M. MINNESOTA GAS UTILITIES' PURCHASING PRACTICES

In its August 11, 2014 *Order* in Docket No. 13-600, as part of Order Point No. 3, the Commission requested the Department to provide a review of gas purchasing practices to be included in future annual automatic adjustment reports. Specifically, the Commission requested a discussion of the Department's portfolio analysis (gas purchasing practices) and storage rates analysis (discussed in Section N).

The Department analyzes gas procurement in various ways throughout the year, for example:

- review of the utilities' PGAs and filing of subsequent reports;
- individual meetings with utilities regarding their respective procurement plans for the upcoming year; and
- annual winter pricing recap presentations by the utilities for the Commission.

The Department notes that purchasing practices differ between utilities based on resources available. CenterPoint Energy, MERC, and Xcel Gas use hedging. Great Plains does not have access to storage in its northern service territory, and GMG procures storage only for balancing purposes. Utilities that have peak-shaving facilities are CenterPoint Energy and Xcel Gas.[173] GMG uses outside sources to assist in managing its gas resource portfolio.[174] Thus, each gas supply portfolio is unique to the utility.

In addition, gas utilities have various ways to purchase natural gas. For example, the largest share of all natural gas purchases, across all utilities, comes from monthly index-priced gas.[175]

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[172] Xcel Gas' AAA Report, Attachment G, page 12.
[173] Department Information Request No. 12. Responses available upon request.
[174] GMG's AAA Report, page 2.
[175] Monthly index-priced gas refers to gas purchased under a term contract longer than one day that establishes the price at which the gas will be purchased each month of the contract based upon indexes published on the first day of each month for gas purchased at a major trading point (*e.g.*, Demarc, Ventura) and delivered to the utility's city gate.

Other types of purchases include daily spot-priced gas,[176] daily index-priced gas,[177] or fixed price gas.[178]

Commodity prices for all types of gas purchases have been, generally, at or below $4.50 since FYE15. Thus, a detailed analysis of the differences in non-weighted average prices between the various types of purchases does not necessarily shed new light on utilities' gas purchasing practices. That said, the Department will continue to analyze the information each year. If price differences between the various types of gas purchases begin to widen again, or if the types of gas that utilities rely on shift significantly, the Department will include a more detailed analysis.

N. PER-UNIT STORAGE COST OF GAS AND PERCENTAGE OF STORAGE

Using data from Department Information Request No. 11, the Department compared the non-weighted average FYE18 per-unit storage cost of gas for the individual utilities. Additionally, using data from Department Information Request No. 5(c), the third column shows, by utility, the percentage of storage used, or withdrawn, during the reporting period compared to the utility's total gas portfolio. The results are shown below in Table G31.

Table G31[179]: FYE18
Actual Per-Unit Storage Cost and Percentage of Storage

Utility/System	Storage Costs ($/Mcf)	Percent of Winter Portfolio Comprised of Storage (%)
Greater Minnesota	$1.33	32.45%
Great Plains	$2.75	9.94%
MERC		
Consolidated	$0.00	0.00%
NNG	$2.63	27.76%
CenterPoint Energy	$2.92	27.03%
Xcel Gas	$2.79	13.65%
MN Weighted Avg.	**$2.83**	
MN Non-Weighted Avg.	**$2.48**	

[176] Daily spot-priced gas purchases refers to gas purchased on the daily spot market, at market prices under a contract that is in effect for only one day or purchase, and delivered to the utility's city gate.
[177] Daily index-priced gas refers to gas purchased under a term contract at a price that is based on and varies with a daily index price at a major trading point (*e.g.*, Demarc, Ventura) and is delivered to the utility's city gate.
[178] Storage gas is not included in this discussion, since storage gas includes all methods, or types, of purchased gas. Thus, storage gas is a subset of total gas purchases and its price is determined by the cost of various types of purchased gas.
[179] The storage costs listed in this table relate to total storage costs for the entire reporting period, while the portfolio percentages relate solely to those used during the five-month heating season.

Table G31 indicates that the actual storage costs, for utilities that used storage for purposes other than balancing, ranged from a low of $1.33 per Mcf for GMG to a high of $2.92 per Mcf for CenterPoint Energy. The Minnesota non-weighted average cost of storage was $2.48 per Mcf. Additionally, the percentage of storage gas withdrawn during the winter as part of the utility's total winter volumes ranged from a low of 0.00 percent for MERC-Consolidated to a high of 32.45 percent for GMG. Thus, 32.45 percent of GMG's total portfolio for FYE18 was storage gas withdrawn at an average cost of $1.33 per Mcf.

Certain qualifications should be considered when comparing storage costs. For instance, a trade-off between price and reliability applies to storage supplies. Gas supplies in storage fields are often a step removed from gas-producing fields and gathering facilities, thereby providing a greater reliability of supplies during sustained cold periods that may affect wells in the production fields. While gas injected into storage during the non-heating season generally costs less than gas purchased during the heating season,[180] the added cost of using storage facilities and services may result in a higher final per-unit price of the storage gas than gas purchased during the heating season directly from the supplier. However, utilities have more control in using their own storage gas during peak situations. Therefore, the trade-off between price and reliability should be an important consideration in each utility's gas portfolio decisions.

O. MINNESOTA GAS UTILITIES' HEDGING PRACTICES

In its August 11, 2014 *Order Accepting Gas Utilities' Annual Reports and 2012-2013 True-Up Proposals and Setting Further Requirements* in Docket No. 13-600, the Commission requested that the Department provide a review of hedging practices in its review of future annual automatic adjustment reports. Additionally, at its February 4, 2016 Commission Agenda meeting regarding CenterPoint Energy's hedging variance filing in Docket No. G008/M-15-912, the Commission expressed interest in taking a closer look at utility hedging practices given the current state of the natural gas market. On June 28, 2016, the Commission held a Planning Meeting to discuss hedging. A presentation was provided by the utilities that participate in hedging (CenterPoint, MERC, and Xcel).

Background

The goal of hedging is to use appropriate strategies to minimize the risk of cost increases for any given degree of reduced volatility. In a sense, a hedge is an insurance policy that, for a fee, protects utilities (and their ratepayers) against a specific (unfavorable) event occurring during the term of a policy. (An example of such an event is when Hurricane Katrina devastated

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[180] Excluding outside factors affecting the natural gas industry that may lead to unusual price fluctuations. This could be from weather-related interruptions or equipment failure. In addition, prices have not always followed this convention since the glut of gas supply from fracking and other non-conventional natural gas extraction methods have become mainstream.

Southern States, including areas where natural gas facilities were located. Natural gas costs skyrocketed immediately.) Hedging can be used to reduce gas price risk by generating a payment in the event that the market price of natural gas moves in an unfavorable (and unpredicted) direction. The goal is not to guarantee the lowest priced gas but to mitigate price volatility, provide reasonably priced natural gas and ensure reliability. There are a number of hedging tools/instruments available in the derivative market such as futures contracts, commodity swaps, "costless" collars, and options.[181]

Three Minnesota LDCs have received Commission approval to recover the costs of financial hedging through their PGAs: CenterPoint Energy, MERC, and Xcel Gas. The Commission also orders financial hedging restrictions based on utility-specific circumstances and information. A more thorough analysis is performed for CPE, MERC, and Xcel Gas in the utilities' respective variance filings, which allow these companies to recover hedging costs through their PGA filings.

Weather and various supply issues play a significant role in the commodity price of natural gas, especially during the heating season of November through March. As previously discussed in Section 1.C. *Natural Gas Prices and Weather*, the 2017-2018 heating season was overall colder than normal. As discussed above, natural gas prices remained relatively stable during the reporting period, except for a short period of high prices in January 2018. Natural gas storage inventory level in FYE18 was squarely within the previous five-year range, until January 2018, when storage levels dropped to a five-year low. After the cold snap at the end of December to the beginning of January, storage levels rebounded back above the five-year minimum, but were still below the five-year average.

Based on the 2017-2018 heating season, the Department expected that CPE, MERC, and Xcel Gas would experience larger losses on the hedge portion of their purchase portfolios in November, February, and March, but would see smaller losses, or even financial gains, in December and January. The following discussion reviews the performance of each utility's hedging program against this expectation.

MERC

MERC uses a 40%/30%/30% hedging strategy to mitigate price volatility and provide reasonably priced natural gas; 40 percent of normal winter requirements are purchased at a first-of-month (FOM) index price, 30 percent are supplied by physical storage, and 30 percent are covered by financial hedges (10 percent futures and 20 percent call options).[182]

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[181] Definitions and examples of each tool are provided in the glossary that is included as Attachment G3.
[182] MERC's *Annual Automatic Adjustment Report*, page 1.

In Docket No. G011/M-15-231, MERC was granted an extension of a rule variance that allows MERC to recover the costs associated with certain financial instruments through the PGA through June 30, 2017. In Docket No. G011/M-17-85, MERC was granted an additional extension to its variance through June 30, 2021. For details on previous variance dockets and compliance requirements, please see Section II.C.3. *Compliance and/or Supplemental Reporting Requirements*.

Regarding FYE18, MERC stated, in its response to the Department's Information Request No. 15(H), that there were no changes to the financial hedging program compared to the previous reporting period.

In 2017-2018, MERC's hedging portfolio provided gas at a higher cost than if it did not hedge, which is consistent with expectations.[183] Hedges reduce volatility in gas prices but do so for a fee. Since weather was only slightly colder-than-normal, and that the cold snap in January 2018 was short-lived, this outcome is within expectations. The Department concludes that MERC accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

CenterPoint Energy

CenterPoint Energy's policy is to provide price stabilization for a portion of its winter supply through hedge gas purchases and storage gas. The level of price stabilization to be achieved is re-determined each year based on an analysis that incorporates regulatory guidelines (as to volumes and costs), winter price projections, and available portfolio assets.[184]

In Docket No. G008/M-15-912, CenterPoint Energy was granted an extension, through June 30, 2020, to a rule variance that allows CPE to recover the costs associated with certain financial instruments through the PGA. For details on previous variance dockets and compliance requirements, please see Section II.E.2 *Compliance and/or Supplemental Reporting Requirements*.

In its response to the Department's Information Request No. 15(H), CenterPoint Energy stated that there was no significant change in its hedging program from the previous year.

Regarding its hedging strategy for the 2017-2018 winter season, CPE stated,[185]

[183] *Id.*, Trade Secret Schedule L.
[184] CenterPoint Energy's *Annual Automatic Adjustment Report*, page 8.
[185] *Id.*, page 12.

> Contract storage allows for the purchase of gas during summer months when prices are typically lower, and withdrawal for system use during winter months resulting in a natural price hedge. Storage also provided daily operational benefits for which it was purchased. Storage volumes represented 26% of the winter system supplies. Physical base load gas purchases containing price protections were made over several months during the summer using multiple RFP's. CenterPoint Energy purchased 23.0 Bcf of total hedged supply and, when combined with 26.2 Bcf of storage volumes, provide stabilized prices for 48.6% of winter gas supplies.
>
> In addition to providing price stability, the price hedges also provide catastrophic price protection against price fly-ups during unforeseen events such as upstream pipeline ruptures and prolonged extremely cold weather.
>
> Market prices for winter gas (futures winter strip) during 2017 for the most part stayed below $3.50 until June and hovered between $3.00 and $3.50 for the rest of the season.

According to CenterPoint Energy, hedged gas purchases were approximately $8.28 million (or $0.3274 per dekatherm)[186] lower during the winter period when compared to buying gas at actual First of Month index pricing.[187]

CenterPoint Energy's hedges provided a financial gain in FYE18 due to the higher prices experienced in the winter months; since the weather was colder than normal, this outcome is within expectations. The Department concludes that CenterPoint Energy accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

Xcel Gas

The overall goal of Xcel's Price Volatility Mitigation Plan is to reduce the exposure to and the magnitude of gas price spikes at a reasonable cost to its customers. The goal of the plan is not to attempt to outguess the market or to speculate on the future direction of energy prices.[188] The purpose of Xcel's seasonal strategy is to reduce the potential risk of short-term upsets in the wholesale gas markets and the resulting gas price spikes.[189]

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[186] *Id.,* page 24.
[187] *Id.*, page 12.
[188] Xcel Gas' *Annual Automatic Adjustment of Charges Report*, Attachment A, Schedule 5, page 2.
[189] *Id.*, page 3.

In Docket No. G002/M-16-88 (Docket 16-88), Xcel Gas was granted an extension, through June 30, 2020, to a rule variance that allows Xcel Gas to recover the costs associated with certain financial instruments through the PGA. For details on previous variance dockets and compliance requirements, please see Section II.F.2 *Compliance and/or Supplemental Reporting Requirements*.

In its response to the Department's Information Request No. 15(H), Xcel Gas stated that there were no changes to the financial hedging program for the period July 1, 2017 through June 30, 2018.

Xcel Gas' hedges provided a financial loss of approximately $412,000 in FYE18 due to the lower prices experienced during most of the winter.[190] As expected, Xcel Gas experienced losses on most of its hedges but experienced financial gains on a few of its executed transactions. The Department concludes that Xcel Gas accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

Conclusion and Recommendations

As discussed above, MERC and Xcel Gas experienced losses due to hedging during FYE18 and CenterPoint realized a financial gain. While this is an overall cost to MERC and Xcel Gas ratepayers, there was protection in place in case additional or more severely adverse events occurred. Moreover, the Department observes that the natural gas purchases covered by hedges were only a portion of the total winter requirements purchased, allowing all three utilities to avoid catastrophic prices for portions of their portfolios and to take advantage of lower prices on other parts of their portfolios. The ultimate goal of hedging is to reduce price volatility on a percentage of the utilities' purchase portfolios, not to speculate or make money on commodity prices.

The Department concludes that the utilities' hedging programs performed as expected. The Department recommends that each utility that hedges (including physical and financial) continue to provide a post-mortem analysis, in a format similar to what was provided in this docket, in subsequent AAA filings.

IV. SUMMARY OF THE DEPARTMENT'S RECOMMENDATIONS

The Department includes a number of specific recommendations for future annual automatic adjustment reports to ensure full compliance with Commission Orders and Minnesota Rules 7825.2700 and 7825.2910, and to improve accountability. The Department summarizes its recommendations below.

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[190] *Id*., Attachment G, Trade Secret Schedule 2.

1. The Department recommends that the Commission accept the FYE18 annual reports as filed by the gas utilities as being complete as to Minnesota Rules 7825.2390 through 7825.2920.

2. The Department recommends each utility that hedges (including physical and financial) continue to provide a post-mortem analysis, in a format similar to what was provided in this docket, in subsequent AAA filings.

A. GREATER MINNESOTA

The Department recommends that the Commission:

- accept GMG's FYE18 true-up as filed in Docket No. G022/AA-18-563; and
- allow GMG to implement its true-ups, as shown in Department Attachment G5 of the FYE18 AAA Report.

B. GREAT PLAINS

The Department recommends that the Commission:

- accept Great Plains' FYE18 true-ups, Docket No. G004/AA-18-567; and
- allow Great Plains to implement its true-ups, as shown in Department Attachments G6a and G6b of the FYE18 AAA Report.

C. MERC

The Department recommends that the Commission:

- accept MERC-NNG's FYE18 true-up filing in Docket No. G011/AA-18-489;
- allow MERC-NNG to implement its true-up, as shown in Department Attachment G8 of the FYE18 AAA Report;
- accept MERC-CON's FYE18 true-up filing in Docket No. G011/AA-18-490; and
- allow MERC-Consolidated to implement its true-up, as shown in Department Attachment G9 of the FYE18 AAA Report.

Additionally, the Department recommends that MERC conduct its investigation into negative LUF on both its NNG and Consolidated PGA systems.

The Department also requests that MERC provide in its *Reply Comments* a discussion of the treatment of its gas losses due to damages for each PGA system.

In future AAA Reports, the Department requests that MERC provide totals for Schedule Q.

Finally, the Department requests that MERC provide a discussion in *Reply Comments* regarding the party that caused the most strikes on its system than any other party. This discussion should include, but not be limited to, whether the level of strikes by this party is typical and any action MERC has taken to reduce strikes caused by the party.

D. CENTERPOINT ENERGY

The Department recommends that the Commission:

- accept CenterPoint Energy's FYE18 true up, Docket No. G008/AA-18-573; and
- allow CenterPoint Energy to implement its true up, as shown in Department Attachment G10 of the FYE18 AAA Report.

The Department requests that CenterPoint provide in *Reply Comments* a discussion of the treatment of its gas losses due to damages for each PGA system.

Finally, the Department requests that CenterPoint Energy provide a discussion in *Reply Comments* regarding the party that caused the most strikes on its system than any other party. This discussion should include, but not be limited to, whether this level of strikes is typical and any action CPE has taken to reduce strikes caused by the party.

E. XCEL GAS

The Department recommends that the Commission:

- accept Xcel Gas' FYE18 true-up, Docket No. G002/AA-18-572; and
- allow Xcel Gas to implement its true-up, as shown in Department Attachment G11 of the FYE18 AAA Report.

The Department requests that Xcel Gas provide, in its *Reply Comments*, a list of unauthorized gas use during the 2018-2019 heating season in the same detail as its compliance filing submitted in this instant docket on March 22, 2019. The Department also requests that Xcel include a discussion detailing all barriers to further reducing unauthorized usage, and suggesting possible solutions.

The Department requests that Xcel provide in *Reply Comments* its analysis of which rule applies to the High Bridge Adjustment. In addition, the Department requests that Xcel Gas provide the amounts that should be surcharged and/or refunded associated with each year in which the SCADA readings were erroneously provided to NNG assuming Minnesota Rule 7825.2920 applies, and the same information assuming Minnesota Rules 7820.3800/7820.4000 apply.

The Department recommends that in *Reply Comments*, Xcel Gas provide the detailed calculations supporting its High Bridge adjustment, including a reconciliation of the $3.7 million and $5.2 million totals provided in the Company's filings.

Finally, the Department recommends that Xcel file a supplemental filing in Docket No. E999/AA-18-373 as soon as possible, so the High Bridge issue can be addressed in *Reply* and *Response Comments* in that docket. The Department recommends that the filing contain, at a minimum, a discussion of the allocation error, the underlying calculations and reconciliations for the adjustment(s) broken down by customer class, and a legal analysis as to whether Minnesota Rule 7825.2920 applies to any adjustment proposed or needed to Xcel Electric's fuel clause adjustment or whether Minnesota Rule 7820.3800 applies.

F. ALL REGULATED UTILITIES

The Department recommends that, going forward, the Commission require all regulated gas utilities to demonstrate whether each, prior-period adjustment made in an Annual True-Up filing is subject to the Billing Error Rule.

As a reminder to the hedging utilities, in Docket No. G999/AA-17-493 the Commission ordered:

> CenterPoint Energy, MERC, and Xcel Gas shall provide, in their reply comments for the 2017 – 2018 reporting year and the five previous reporting years, the following information:
>
> - The annual cost of each hedging tool used both in real dollars and as a percent of their actual incurred gas costs;
> - A comparison of the hedging tool cost to that if the utility would have purchased the gas using the actual 1st of the month index pricing or any other cost comparison the companies believe would be helpful in consultation with the Department;
> - A nationally recognized index of gas price volatility for each of the years along with an explanation of the index used; and
> - A discussion of the particular company-specific trends in using hedging tools and how that has informed their strategy moving forward.

/ja

FYE18
RECORDED UNWEIGHTED HEATING DEGREE DAYS

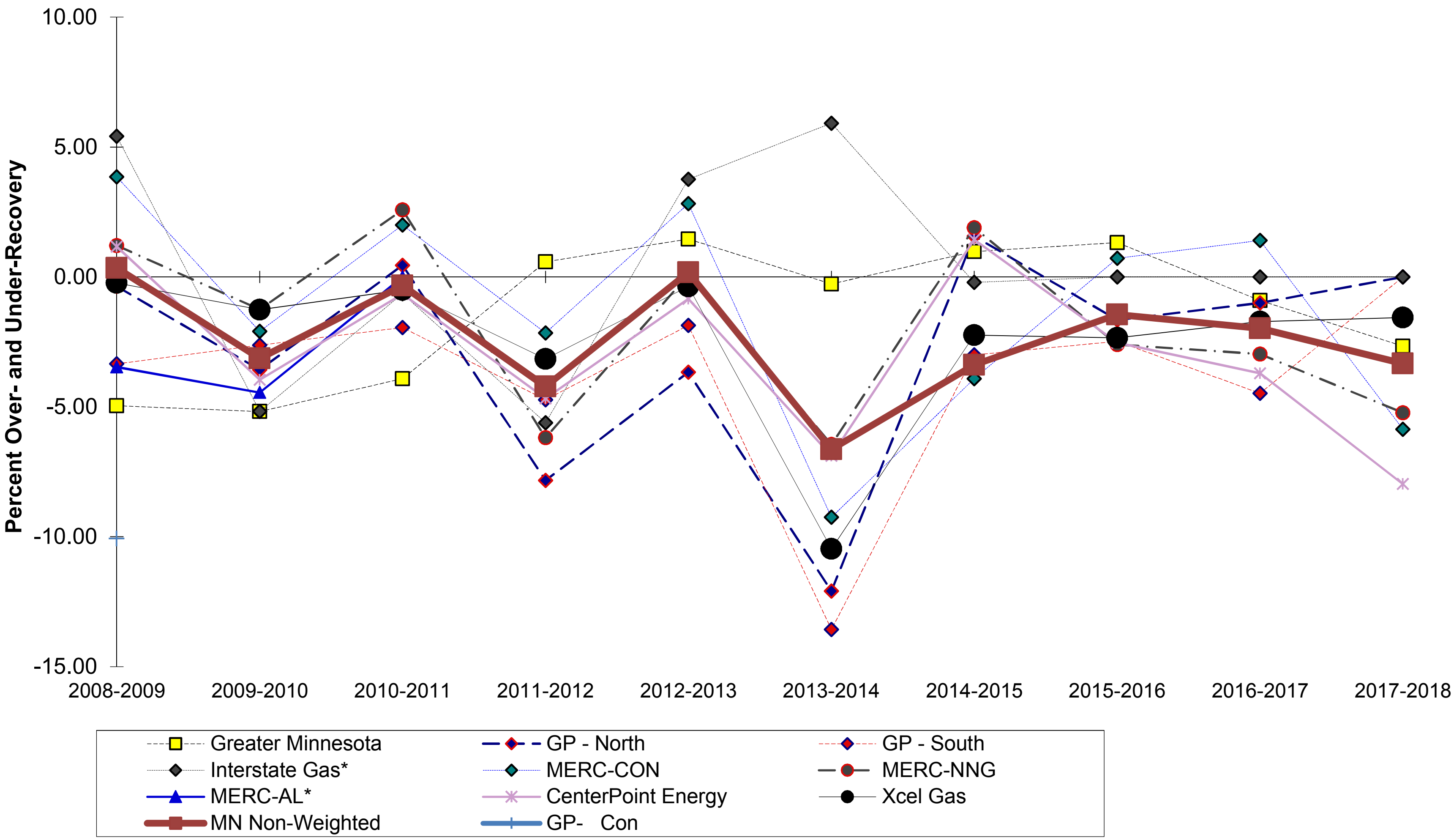
Annual Data											
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2012-2013	Season 2013-2014	Season 2014-2015	Season 2015-2016	Season 2016-2017	Season 2017-2018	2017-2018 vs. Normal (71-00)	2017-2018 vs. Normal (81-10)	2017-2018 vs. Prior 5-Yr. Avg.
DULUTH	9,709	9,444	9,366	10,342	9,276	8,186	8,138	9,560	-1.53%	1.23%	5.50%
INTERNATIONAL FALLS	10,216	10,221	10,713	11,511	10,283	8,995	9,088	10,454	2.33%	2.28%	3.32%
FARGO, ND	9,019	8,802	9,403	9,679	8,469	7,172	7,452	8,912	-1.19%	1.25%	5.66%
ST CLOUD	8,744	8,532	8,872	9,524	8,143	7,170	7,327	8,687	-0.65%	1.82%	5.85%
MPLS/ST PAUL	7,805	7,580	7,708	8,597	7,528	6,283	6,310	7,579	-2.90%	-0.01%	4.03%
ROCHESTER	8,150	7,722	7,825	8,917	8,068	6,796	6,900	8,065	-1.04%	4.44%	4.72%
SIOUX FALLS, SD	7,683	7,706	7,884	8,320	7,568	6,380	6,463	7,569	-1.48%	-1.78%	3.36%

Winter Data (November 2017 - March 2018)											
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2012-2013	Season 2013-2014	Season 2014-2015	Season 2015-2016	Season 2016-2017	Season 2017-2018	2017-2018 vs. Normal (71-00)	2017-2018 vs. Normal (81-10)	2017-2018 vs. Prior 5-Yr. Avg.
DULUTH	7,169	6,952	6,822	8,028	7,145	6,046	6,136	7,242	1.02%	4.17%	5.95%
INTERNATIONAL FALLS	7,728	7,589	7,747	8,869	7,691	6,574	6,750	7,922	2.51%	4.39%	5.26%
FARGO, ND	7,145	7,589	7,226	7,849	6,873	5,758	5,974	7,139	-0.08%	-5.93%	5.98%
ST CLOUD	6,853	6,665	6,731	7,724	6,583	5,609	5,784	6,865	0.18%	3.00%	5.84%
MPLS/ST PAUL	6,295	6,108	6,040	7,117	6,257	5,121	5,234	6,204	-1.45%	1.57%	4.20%
ROCHESTER	6,437	6,136	6,052	7,297	6,553	5,427	5,606	6,408	-0.45%	4.43%	3.57%
SIOUX FALLS, SD	6,157	6,105	6,037	6,813	6,278	5,274	5,255	6,075	-1.33%	-0.49%	2.42%

Source: MN Dept of Natural Resources, Heating/Cooling Degree Day Table
http://www.dnr.state.mn.us/climate/historical/energy.html

Prepared by the Minnesota Commerce Department, Division of Energy Resources

Regulated Minnesota Gas Utilities
Present Year Percent
Over-Recovery/(Under -Recovery) as Filed



Prepared by the Minnesota Commerce Department

GLOSSARY

TERMS AND ACRONYMS	*DEFINITION*
ACA	*Annual Charge Assessment* is a charge paid to the Federal Energy Regulatory Commission (FERC) to defray the agency's administrative costs.
Brokered Reservation Charge	This demand component of the Purchased Gas Adjustment (PGA), which is reservation charges paid to the supplier of natural gas for transportation and other costs incurred to reserve upstream pipeline capacity to get gas.
C/I	*Commercial/Industrial*.
DDVC	*Daily Delivery Variance Charge* - Shippers are required to take actual daily volumes at their delivery point(s) as close to daily scheduled volumes as possible. In the event that actual daily volumes vary from daily scheduled volumes, Shippers are subject to Daily Delivery Variance Charges (DDVC) after a tolerance has been considered.
LGS	*Large General Service.*
LMS	*Load Management Service* is Viking's no-notice service used to provide additional tolerances for shippers, beyond the allowed 5 percent tolerance.
LVDF	*Large Volume Duel Fuel.*
LVI	*Large Volume Interruptible.*
MDQ	*Maximum Daily Quantity.*
PGA (LDCs)	*Local Distribution Company's Purchased Gas Adjustment* is a mechanism used by regulated utilities to recover its cost of energy. Minnesota Rules 7825.2390 through 7825.2920 enable regulated gas (and electric) utilities to adjust rates on a monthly basis to reflect changes in its cost of energy delivered to customers based upon costs authorized by the Minnesota Public Utilities Commission in the utility's most recent general rate case.

TERMS AND ACRONYMS	*DEFINITION*
SBA	*System Balancing Agreements* are contracts between Northern Natural Gas (Northern) and shippers on its system who agree to use their facilities and supplies to maintain Northern's system integrity. Costs to Northern for such services are recovered with a surcharge.
SMS	*System Management Service* is Northern's no-notice service which provides additional tolerances for shippers, beyond the allowed 5% tolerance.
SOL	*System Overrun Limitation* is a parameter or boundary that limits the use of SMS service on days which Northern's system integrity is threatened and SBA provisions are not adequate in maintaining pipeline operations.
SVDF	*Small Volume Dual Fuel.*
SVF	*Small Volume Firm.*
SVI	*Small Volume Interruptible.*
Throughput Services	*Throughput Services* may be defined as the Total Aggregate MDQ for a shipper in Northern's Market Area. This Total Aggregate MDQ is the total of the individual MDQs of TF12-B, TF12-V, and TF5. A shipper's Total Aggregate MDQ is per contract with Northern; however, the three individual MDQs (used for billing purposes) are subject to limitations. First, TF5 cannot exceed 30 percent of Total Aggregate MDQ. Next, the remainder is split between TF12-B and TF12-V on the contract's anniversary date, with the TF12-B equaling total town border station (TBS) deliveries for the previous May through September. Thus, TF12-V would equal Total Aggregate MDQ less TF5 and TF12-B. These services are available in the Market Area only.

TERMS AND ACRONYMS	*DEFINITION*
TF12-B	*Transportation - Firm for 12 months - Base Level.* See Throughput Services.
TF12-V	*Transportation - Firm for 12 months - Variable Level.* See Throughput Services.
TF5	*Transportation - Firm for 5 months*. See Throughput Services.
TFX	*Transportation - Firm* (Negotiable terms) is available to any shipper to acquire firm transportation services where the service needed is not conducive to the parameters set out under Throughput Services.
TI	*Transportation - Interruptible*.

Hedging Terms and Examples

TERMS AND ACRONYMS	*DEFINITION*
Futures Contracts	Firm commitments to make or accept delivery of a specified quantity and quality of a commodity during a specific month in the future at a price agreed upon at the time the commitment is made.
Futures Contract Example	Party A expects to need gas in January and wants to make sure that they do not have to pay more than $5.60. Party A buys a contract for January gas at $5.60 to lock in the price. As the strike date approaches, the futures price should – and usually does – converge towards the bidweek prices. If the bidweek price for gas at Henry Hub is $6.15, the purchaser buys physical gas for $6.15 and sells the future contract back at the prevailing future market price, around $6.15 per MMBtu. Party A has a gain of $0.55 per MMBtu on the future transaction. The gain on the futures contract offsets the fact that Party A was forced to buy gas at $6.15 per MMBtu. When the cost of the gas is combined with the "gain" on the future contract, the

Terms and Acronyms	*Definition*
	"net" gas cost is $5.60 per MMBtu, which was the locked in price. If, however, the bidweek price for gas is $5.25 per MMBtu, the purchaser will buy their gas for $5.25 and take a $0.35 loss on the futures contract. Nevertheless, the "net" cost remains $5.60 per MMBtu because the loss is "offset" by the fact that Party A can buy the gas at a lower price.
Gas Prices	
Citygate Price	The price for gas delivered at the citygates. Citygates are the transfer point or measuring station at which upstream pipelines connect to the LDC's distribution system.
Retail Price	The price charge to the ultimate consumer.
Spot Prices	The price for a one-time, open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.
Wellhead Price	The price of crude oil or natural gas at the mouth of the well.
Hedging	A trade designed to reduce risk. Usually done by covering future commitments at a fixed price in the future, through either options or futures contract.
Marginal Prices	The price of the next increment of supply. Published data generally presents daily averages for weekdays (excluding holidays).
Non-commercial Open Interest	The net non-commercial open interest represents total "long" open interest contracts minus total "short" positions held by non-commercial customers. It represents a reasonable proxy for speculative positions in natural gas futures markets. Natural gas prices tend to increase when net non-commercial open interest is above zero and to decrease when net non-commercial open interest is below zero.

Terms and Acronyms	*Definition*
Open Interest	The number of open or outstanding contracts for which an individual or entity is obligated to an exchange because that individual or entity has not yet made an offsetting sale or purchase, an actual contract delivery, or in the case of options, exercised the option.
Options	A contract between two parties in which one party has the right, but not the obligation, to buy or sell an underlying asset.
Call Option	An option that gives the holder the right (but not the obligation) to buy a futures contract at a fixed price, on or before a specified date. The grantor of the option is obliged to sell the futures contract at the fixed price if the holder exercises the option.
Call Option Example	Party A buys a call option for the month of May with a strike price of $5.10 for $0.26 to insure against a large price increase. If the May price is $5.50 per MMBtu, the value of the option is $0.40. Party A can sell the option at the strike date for a net gain of $0.14. Party A would then buy the physical gas of the market price of $5.50 per MMBtu for a net gas cost of $5.36. If the May price drops to $4.00 per MMBtu, the value of the option is zero and Party A loses the entire initial cost of the option for a net loss of $0.26. Party A would then buy the physical gas at the market price of $4.00 per MMBtu for a net cost of $4.26 per MMBtu which is well below the strike price of the option.
Put Option	An option that gives the holder the right (but not the obligation) to sell a specified futures contract at a fixed price, on or before a specified date. The grantor of the option has the obligation to take delivery of the futures contract if the option is exercised.
Strike Price	The price at which an option holder has the right to buy or sell and underlying commodity/derivative.

TERMS AND ACRONYMS	*DEFINITION*
Risk-free Rate	The rate of interest that can be earned without assuming any risk.
Out-of-the-Money Option	An option which has no intrinsic value. A put option is out-of-the-money when its strike price is below the value of the underlying futures contract. A call option is out-of-the-money when its strike price is above that of the underlying futures contract.
Price Collar	A contract between a buyer and seller of a commodity whereby the buyer is assured that he will not have to pay more than some maximum price and whereby the seller is assured of receiving some minimum price. Under the terms of a collar, no payment is made when the index price falls within the dead band. A payment is made when the cash price falls outside the "dead band" based upon the difference in the index price and the limit of the dead band. The other party charges an origination fee for the collar.
Price Collar Example	A purchaser, wanting to insure against large price increases, buys a three-month collar at $6.00 per MMBtu with a $0.15 spread around the $6.00 price. If the cash price is between $5.85 and $6.15, no payment is made on the collar. Over the three-month period, the index price for physical gas averages $6.25 per MMBtu. The purchaser buys gas at index, but is paid $0.10 on the collar for a net cost of gas of $6.15. If the index price averages $5.70, the purchaser buys at index but has to pay $0.15 on the collar for a net cost of gas of $5.85 per MMBtu. If the average of index price over the three-month period falls between $5.85 and $6.15, no payment is made for the collar.

TERMS AND ACRONYMS	*DEFINITION*
Price Range	The spread of prices during a specific period. In markets with a uniform product and an open bidding process (e.g., the stock market), the range is often defined as the average spread between the bid price and the ask price during a specific time period. For markets without a uniform product, and where bid and ask prices are not typically available (such as natural gas markets for all locations with the possible exception of the NYMEX Henry Hub contract), the range is typically measured as the difference between the daily high price and the daily low price.
Commodity Swap	A contract between two parties. A swap differs from a futures contract in that it specifies "marker" price that does not vary during the term of the contract. The contract obligates the parties to make payment equal to the difference between the cash price and the "trigger" price. If the cash price is above the "trigger" price, the seller of the swap pays the buyer, if the cash price is below the "trigger," buyer pays the seller. The terms of settlement can be negotiated between the parties, thus there are an almost infinite variety of swaps. For natural gas swaps, it is particularly valuable to commercial interests to be able to enter in swap at specific locations along the gas pipeline system (i.e., interconnects, citygates, and pipeline receipt and delivery points, etc.)
Commodity Swap Example	A purchaser wanting to lock in a $6.00 price for gas at Ventura over the next 3 months signs a swap agreement with another party. Over the three-month period, the index price averages $6.25 per MMBtu. The purchaser buys the physical gas at the index price of $6.25 and is paid $0.25 on the swap for a "net" gas cost of $6.00. If however, the price averages $5.70 per MMBtu, the purchaser buys at the index price but has to pay $0.30 per MMBtu to the other party under the terms of the swap. The net gas cost remains $6.00 per MMBtu.

Throughput Services	CPE	Great Plains	GMG	MERC NNG	MERC-CON	Xcel Gas
NNG TF-12	D	D	D	D		D
NNG TF-5	D	D	D	D		D
NNG TFX	D	D	D	D		D
Viking FT-A	D	D			D	D
Great Lakes FT					D	D
ANR FTS-1						D
WBI FT						D
Centra FT					D	
Balancing, Storage, Reservation Fees						
Balancing SMS, LMS **2/**	A	A	C	C	C	C
NNG storage FDD	A	A		C **1/**	C **1/**	A
NGPL storage	A					
BP Canada storage						
Niska storage						
ANR storage						A
AECO storage					C **1/**	
Other supplier or producer reservation fees	A					

D=Demand cost
A=Costs are allocated to firm and interruptible classes costs
C=Commodity cost

1/ The Commission's Aug. 6, 2014 Order in Docket Nos. G007/M-07-1402, G011/M-07-1403, G011/M-07-1404, and G011/M-07-1405 approved moving storage into commodity as of Nov. 1, 2014.

2/ The Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-up Proposals, and Setting Further Requirements* in Docket No. 12-756 required all regulated gas utilities to prospectively recover balancing service costs, and credit the utility's penalty revenues and the pipeline's revenue

Greater Minnesota Gas, Inc.
2017-2018 True Up
Docket No. G022/AA-18-563
As Filed on August 30, 2018

Ten Year Summary of Gas-Cost Recovery

Year Ended 6/30	**Present Year Percent Over (Under) Recovery**	**Cumulative Percent Over (Under) Recovery**
2008-2009	-4.96%	
2009-2010	-5.18%	
2010-2011	-3.92%	
2011-2012	0.58%	
2012-2013	1.46%	
2013-2014	-0.27%	
2014-2015	0.98%	
2015-2016	1.32%	
2016-2017	-0.91%	
2017-2018	**-2.67%**	**-2.66%**
10 Year Average	-1.36%	

Recovery By Class

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PREVIOUS TRUE-UP OVER/(UNDER) ENDING BALANCE
FIRM	$4,558,050	$4,685,793	($127,743)	**-2.73%**	($2,641)
AGRICULTURAL - INTERRUPTIBLE	$488,069	$507,366	($19,297)	**-3.80%**	$5,326
GENERAL - INTERRUPTIBLE	$370,391	$372,123	($1,732)	**-0.47%**	($1,861)
TOTAL	**$5,416,510**	**$5,565,282**	**($148,772)**	**-2.67%**	**$824**

	(6) (3)+(5)	(7) (6)/(2)	(8)	(9) (6)/(8)
	CUMULATIVE OVER/(UNDER) BALANCE	CUMULATIVE %	Estimated Sales (Mcf)	True Up (Refund)/Collection
FIRM	($130,384)	**-2.78%**	1,211,440	**$0.1076**
AGRICULTURAL - INTERRUPTIBLE	($13,971)	**-2.75%**	70,710	**$0.1976**
GENERAL - INTERRUPTIBLE	($3,593)	**-0.97%**	140,500	**$0.0256**
TOTAL	**($147,948)**	-2.66%	**1,422,650**	

Greater Minnesota Gas, Inc.
2017-2018 True Up
Docket No. G022/AA-18-563
As Filed on August 30, 2018

RECOVERY BY CLASS	(1)	(2)	(3)	(4)
			(1) - (2)	(3) / (2)
RESIDENTIAL - FIRM	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND COST	$571,806	$553,893	$17,913	3.23%
COMMODITY COST	$2,232,607	$2,371,094	($138,487)	-5.84%
TOTAL	$2,804,413	$2,924,987	($120,574)	-4.12%
COMMERCIAL - FIRM				
DEMAND COST	$25,218	$24,106	$1,112	4.61%
COMMODITY COST	$98,550	$100,753	($2,203)	-2.19%
TOTAL	$123,768	$124,859	($1,091)	-0.87%
INDUSTRIAL - FIRM				
DEMAND COST	$339,965	$344,676	($4,711)	-1.37%
COMMODITY COST	$1,289,904	$1,291,271	($1,367)	-0.11%
TOTAL	$1,629,869	$1,635,947	($6,078)	-0.37%
FLEX RATE - FIRM				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$0	$0	$0	0.00%
TOTAL	$0	$0	$0	0.00%
AG. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$488,069	$507,366	($19,297)	-3.80%
TOTAL	$488,069	$507,366	($19,297)	-3.80%
IND. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$370,391	$372,123	($1,732)	-0.47%
TOTAL	$370,391	$372,123	($1,732)	-0.47%
FLEX RATE - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$0	$0	$0	0.00%
TOTAL	$0	$0	$0	0.00%

Greater Minnesota Gas, Inc.
2017-2018 True Up
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RECOVERY BY COMPONENT	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND COST:				
Residential - Firm	$571,806	$553,893	$17,913	3.23%
Commercial - Firm	$25,218	$24,106	$1,112	4.61%
Industrial - Firm	$339,965	$344,676	($4,711)	-1.37%
Flexible Rate - Firm	$0	$0	$0	0.00%
Agricultural - Interruptible	$0	$0	$0	0.00%
Industrial - Interruptible	$0	$0	$0	0.00%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$936,989	$922,675	$14,314	1.55%
COMMODITY COSTS:				
Residential - Firm	$2,232,607	$2,371,094	($138,487)	-5.84%
Commercial - Firm	$98,550	$100,753	($2,203)	-2.19%
Industrial - Firm	$1,289,904	$1,291,271	($1,367)	-0.11%
Flexible Rate - Firm	$0	$0	$0	0.00%
Agricultural - Interruptible	$488,069	$507,366	($19,297)	-3.80%
Industrial - Interruptible	$370,391	$372,123	($1,732)	-0.47%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$4,479,521	$4,642,607	($163,086)	-3.51%
DETAIL OF DEMAND RECOVERY				
Viking Zone 1	$320,796	$308,564	$12,232	3.96%
Viking Zone 1-2	$16,025	$59,690		
TFX-5	$470,113	$480,653	($10,540)	-2.19%
TFX- 7	$63,341	$57,942	$5,399	9.32%
TFX - 12	$66,715	$54,329	$12,386	22.80%
TF Capacity Release	$0	($32,504)	$32,504	-100.00%
SMS Demand	$0	$0	$0	0.00%
TOTAL	$936,990	$928,674	$8,316	0.90%

Great Plains Natural Gas North District
2017-2018 True-Up
Docket No. G004/AA-18-567
As Filed on August 31, 2018

Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
GP-North	2008-2009	-0.36%	
GP-North	2009-2010	-3.57%	
GP-North	2010-2011	0.45%	
GP-North	2011-2012	-7.83%	
GP-North	2012-2013	-3.66%	
GP-North	2013-2014	-12.09%	
GP-North	2014-2015	1.57%	
GP-North	2015-2016	-1.66%	
GP-North	2016-2017	-1.00%	
GP-Con	2017-2018	**-10.07%**	**-10.05%**
	10-Year Average	-3.82%	

Recovery By Class

	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)	(5)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Recovery	Present Year Over/(Under) Recovery	Prior Year True-Up Over/(Under) Beginning Balance
FIRM	$12,029,245	$13,326,147	($1,296,902)	**-9.73%**	($474,141)
INTERRUPTIBLE	$3,166,159	$3,570,917	($404,758)	**-11.33%**	$63,200
Total	**$15,195,404**	**$16,897,064**	**($1,701,660)**	**-10.07%**	**($410,941)**

	(6)	(7) (3)+(5)+(6)	(8) (7)/(2)	(9)	(10)
	Prior Year Recovery	Cumulative True-Up Over/(Under) Ending Balance	Cumulative %	Projected Sales (Mcf)	True Up Per Mcf (Refund)/Collection
FIRM	$485,255	($1,285,788)	**-9.65%**	2,646,400	**$0.4859**
INTERRUPTIBLE	($71,602)	($413,160)	**-11.57%**	888,700	**$0.4649**
Total	**$413,653**	**($1,698,948)**	**-10.05%**		

Per Docket No. G004/GR-15-879, the North and South Districts' gas costs were consolidated into a single system, effective July 1, 2017. Great Plains presented its annual reporting as one PGA system beginning in this instant docket.

Great Plains Natural Gas North District
2017-2018 True-Up
Docket No. G004/AA-18-567
As Filed on August 31, 2018

	(1)	(2)	(3)	(4)
			(1)-(2)	(3)/(2)
Detail of Current Costs by Class			PRESENT YEAR	PRESENT YEAR
			OVER/(UNDER)	OVER/(UNDER)
FIRM	COST RECOVERY	COST INCURRED	RECOVERY ($)	COLLECTION (%)
Viking				
FT-A (Zone 1-1; Cat. 3)	$384,547	$355,853	$28,694	8.06%
FT-A (Zone 1-1; Cat. 1)	$243,018	$240,136	$2,882	1.20%
FT-A Seasonal	$40,479	$39,182	$1,297	3.31%
FT-A Seasonal	$3,362	$0	$3,362	
BP Contract (Firm Demand)	$30,705	$37,448	($6,743)	-18.01%
Northern Natural Gas				
TFX - Winter/Seasonal	$1,041,727	$882,998	$158,729	17.98%
TFX - Summer	$474,021	$410,264	$63,757	15.54%
TF12 Base - Summer	$179,692	$181,027	($1,335)	-0.74%
TF12 Base - Winter	$230,950	$222,583	$8,367	3.76%
TF12 Variable - Summer	$95,771	$79,951	$15,820	19.79%
TF12 Variable - Winter	$166,847	$166,634	$213	0.13%
TF5	$237,241	$231,617	$5,624	2.43%
TFX - Summer	$73,083	$199,774	($126,691)	-63.42%
TFX - Winter	$501,178	$489,044	$12,134	2.48%
TFX Negotiated Contract - Winter	$123,402	$120,542	$2,860	2.37%
FDD-1 Reservation	$87,699	$84,476	$3,223	3.82%
TFX - Capacity Release	($2,640)	$0	($2,640)	
TF-12 - Capacity Release	($630)	$0	($630)	
Interruptible Demand Credit	($352,900)	($329,804)	($23,096)	7.00%
Total Demand	$3,557,552	$3,411,725	$145,827	4.27%
Commodity Cost	$8,471,693	$9,914,422	($1,442,729)	-14.55%
TOTAL	$12,029,245	$13,326,147	($1,296,902)	-9.73%
INTERRUPTIBLE				
Commodity Cost	$2,836,355	$3,241,113	($404,758)	-12.49%
Interruptible Demand Charge	$329,804	$329,804	$0	0.00%
TOTAL	$3,166,159	$3,570,917	($404,758)	-11.33%

Prepared by the Minnesota Commernce Department, Division of Energy Resources

Great Plains Natural Gas North District
2017-2018 True-Up
Docket No. G004/AA-18-567
As Filed on August 31, 2018

Recovery by Class		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
FIRM					
	Demand	$3,557,552	$3,411,725	$145,827	4.27%
	Commodity	$8,471,693	$9,914,422	($1,442,729)	-14.55%
	Total	$12,029,245	$13,326,147	($1,296,902)	-9.73%
INTERRUPTIBLE					
	LMS Demand	$329,804	$329,804	$0	0.00%
	Commodity	$2,836,355	$3,241,113	($404,758)	-12.49%
	Total	$3,166,159	$3,570,917	($404,758)	-11.33%

Recovery by Component		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
Demand					
	Firm	$3,557,552	$3,411,725	$145,827	4.27%
	Total	$3,557,552	$3,411,725	$145,827	4.27%
Commodity					
	Firm	$8,471,693	$9,914,422	($1,442,729)	-14.55%
	Interruptible	$3,166,159	$3,570,917	($404,758)	-11.33%
	Total	$11,637,852	$13,485,339	($1,847,487)	-13.70%

MERC - NNG
2017-2018 True-up
Docket No. G011/AA-18-489
(As filed on August 31, 2018)

SUMMARY OF GAS COST RECOVERY:

	Year Ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
MERC-PNG	2009	1.21%	
MERC-PNG	2010	-1.25%	
MERC-PNG	2011	2.58%	
MERC-PNG	2012	-6.19%	
MERC-PNG	2013	0.08%	
MERC-Northern System	2014	-6.45%	
MERC-Northern System	2015	1.90%	
MERC-Northern System	2016	-2.60%	
MERC-Northern System	2017	-2.97%	
MERC-Northern System	**2018**	**-5.23%**	**-4.99%**
	10-YEAR AVERAGE	-1.89%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER/(UNDER) BEGINNING BALANCE
GS	$115,258,611	$120,937,956	($5,679,345)	**-4.70%**	$211,043
SVJ/LVJ/SLV Demand	$32,022	$32,022	$0	**0.00%**	$0
SVI/SVJ/LVI/LVJ/SLVI Commodity	$10,392,636	$11,649,136	($1,256,500)	**-10.79%**	$102,299
	$125,683,269	**$132,619,114**	**($6,935,845)**	**-5.23%**	**$313,342**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	CUMULATIVE %	ESTIMATED SALES (DTH)	TRUE-UP FACTORS (REFUND)/COLLECT^
GS	($5,468,302)	-4.52%	24,482,649	$0.2234
SVJ/LVJ/SLV Demand	$0	0.00%	1,140	$0.0000
SVI/SVJ/LVI/LVJ/SLVI Commodity	($1,154,201)	-9.91%	2,837,098	$0.4068
	($6,622,503)	-4.99%	**27,320,887**	

Per Docket No. G011/GR-15-736, the MERC-AL and MERC-NNG gas systems were approved for consolidation per the Commission's October 31, 2016 Findings of Fact, Conclusions, and Order.

MERC - NNG
2017-2018 True-up
Docket No. G011/AA-18-489
(As filed on August 31, 2018)

		(1)	(2)	(3)	(4)
RECOVERY BY CLASS				(1) - (2)	(3) / (2)
General Service (GS)				PRESENT YEAR OVER/(UNDER)	PRESENT YEAR OVER/(UNDER)
		COST RECOVERY	COST INCURRED	COLLECTION ($)	COLLECTION (%)
	DEMAND	$24,595,906	$21,251,657	$3,344,249	15.74%
	COMMODITY	$90,662,705	$99,686,299	($9,023,594)	-9.05%
	TOTAL	$115,258,611	$120,937,956	($5,679,345)	-4.70%
Small & Large Volume Interruptible (SVI/LVI)				PRESENT YEAR OVER/(UNDER)	PRESENT YEAR OVER/(UNDER)
		COST RECOVERY	COST INCURRED	COLLECTION ($)	COLLECTION (%)
	DEMAND	$0	$0	$0	0.00%
	COMMODITY	$10,341,895	$11,592,502	($1,250,607)	-10.79%
	TOTAL	$10,341,895	$11,592,502	($1,250,607)	-10.79%
Small & Large Volume Joint, Super Large Volume (SVJ/LVJ/SLV)				PRESENT YEAR OVER/(UNDER)	PRESENT YEAR OVER/(UNDER)
		COST RECOVERY	COST INCURRED	COLLECTION ($)	COLLECTION (%)
	DEMAND	$32,022	$32,022	$0	0.00%
	COMMODITY	$50,741	$56,634	($5,893)	-10.41%
	TOTAL	$82,763	$88,656	($5,893)	-6.65%

			(1)	(2)	(3)	(4)
RECOVERY BY COMPONENT					(1) - (2)	(3) / (2)
					PRESENT YEAR OVER/(UNDER)	PRESENT YEAR OVER/(UNDER)
			RECOVERY	COST INCURRED	RECOVERY	RECOVERY
DEMAND	GS		$24,595,906	$21,251,657	$3,344,249	15.74%
DEMAND	SVI/LVI		$0	$0	$0	0.00%
DEMAND	SVJ/LVJ/SLV		$32,022	$32,022	$0	0.00%
		TOTAL	$24,627,928	$21,283,679	$3,344,249	15.71%
COMMODITY	GS		$90,662,705	$99,686,299	($9,023,594)	-9.05%
COMMODITY	SVI/LVI		$10,341,895	$11,592,502	($1,250,607)	-10.79%
COMMODITY	SVJ/LVJ/SLV		$50,741	$56,634	($5,893)	-10.41%
		TOTAL	$101,055,341	$111,335,435	($10,280,094)	-9.23%

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

	Year ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
MERC-NMU	2008-2009	3.85%	
MERC-NMU	2009-2010	-2.09%	
MERC-NMU	2010-2011	2.00%	
MERC-NMU	2011-2012	-2.15%	
MERC-NMU	2012-2013	2.82%	
MERC-Consolidated	2013-2014	-9.25%	
MERC-Consolidated	2014-2015	-3.91%	
MERC-Consolidated	2015-2016	0.72%	
MERC-Consolidated	2016-2017	1.41%	
MERC-Consolidated	2017-2018	**-5.86%**	**-6.00%**
	10-YEAR AVERAGE	-1.25%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PRESENT YEAR TRUE-UP OVER/(UNDER) BEGINNING BALANCE
GS	$17,609,150	$18,560,014	($950,864)	**-5.12%**	($33,088)
SVJ Demand	$28,795	$28,795	$0	**0.00%**	$0
SVI/SJV/LVI Commodity	$1,932,224	$2,198,681	($266,457)	**-12.12%**	$2,454
	$19,570,169	**$20,787,490**	**($1,217,321)**	**-5.86%**	**($30,634)**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	**CUMULATIVE %**	Estimated Sales (Dth)	True-Up Factors (Refund)/Collection
GS	($983,952)	**-5.30%**	4,793,801	**$0.2053**
SVJ Demand	$0	**0.00%**	1,320	**$0.0000**
SVI/SVJ/LVI Commodity	($264,003)	**-12.01%**	869,565	**$0.3036**
	($1,247,955)	**-6.00%**	**5,664,687**	

RECOVERY BY CLASS			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
General Service (GS)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$3,977,750	$2,792,446	$1,185,304	42.45%
	COMMODITY		$13,631,400	$15,767,568	($2,136,168)	-13.55%
		TOTAL	$17,609,150	$18,560,014	($950,864)	-5.12%
SVI/SJV/LVI						
	DEMAND		$28,795	$28,795	$0	0.00%
	COMMODITY		$1,932,224	$2,198,681	($266,457)	-12.12%
		TOTAL	$1,961,019	$2,227,476	($266,457)	-11.96%

RECOVERY BY COMPONENT			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
			RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	PERCENT OVER/(UNDER) RECOVERY
DEMAND	General Service (GS)		$3,977,750	$2,792,446	$1,185,304	42.45%
DEMAND	SVI/SVJ/LVJ		$28,795	$28,795	$0	0.00%
		TOTAL	$4,006,545	$2,821,241	$1,185,304	42.01%
COMMODITY	General Service (GS)		$13,631,400	$15,767,568	($2,136,168)	-13.55%
COMMODITY	SVI/SVJ/LVJ		$1,932,224	$2,198,681	($266,457)	-12.12%
		TOTAL	$15,563,624	$17,966,249	($2,402,625)	-13.37%

CenterPoint Energy
2017-2018 True-Up
Docket No. G008/AA-18-573
As Filed on September 4, 2018

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

Year Ended 6/30	PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
2008-2009	1.17%	
2009-2010	-3.96%	
2010-2011	-0.66%	
2011-2012	-4.68%	
2012-2013	-0.84%	
2013-2014	-6.88%	
2014-2015	1.44%	
2015-2016	-2.53%	
2016-2017	-3.71%	
2017-2018	**-7.97%**	**-7.62%**
10-YEAR AVERAGE	-2.86%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (5) / (2)	(5)	(6)	(7) (5) / (2)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	NetPresent Year Over/(Under) Collection (%)	Credits Against Present Gas Costs	Net Present Year Over/(Under) Collection ($)	NetPresent Year Over/(Under) Collection (%)
SVF	$471,734,229	$514,972,147	($43,237,918)	**-8.40%**	$1,396,519	($41,841,399)	**-8.12%**
LGS	$2,301,208	$2,537,366	($236,158)	**-9.31%**	$7,434	($228,724)	**-9.01%**
SVDF	$31,943,376	$34,183,122	($2,239,746)	**-6.55%**	$89,057	($2,150,689)	**-6.29%**
LVDF	$20,408,695	$21,961,458	($1,552,763)	**-7.07%**	$63,169	($1,489,594)	**-6.78%**
	$526,387,508	**$573,654,093**	**($47,266,585)**	**-8.24%**	**$1,556,179**	($45,710,406)	**-7.97%**

	(8)	(9) (5) + (7)	(10) (8) / (2)	(11)	(12) - (8) / (10)
	Prior Year True Up Over/(Under) Balance	Cumulative Over/(Under) Collection ($)	**CUMULATIVE %**	Estimated Sales (DT)	**True-Up Factors (Refund)/Collection**
SVF	$1,542,895	($40,298,504)	**-7.83%**	111,320,000	**$0.3620**
LGS	$58,249	($170,475)	**-6.72%**	645,000	**$0.2643**
SVDF	$366,162	($1,784,527)	**-5.22%**	8,259,000	**$0.2161**
LVDF	$4,526	($1,485,068)	**-6.76%**	6,251,000	**$0.2376**
	$1,971,832	**($43,738,574)**	**-7.62%**	**126,475,000**	

CenterPoint Energy
2017-2018 True-Up
Docket No. G008/AA-18-573
As Filed on September 4, 2018

RECOVERY BY CLASS		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
SMALL VOLUME FIRM		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND		$83,056,610	$85,103,289	($2,046,679)	-2.40%
PROPANE		$0	$190,515	($190,515)	-100.00%
COMMODITY		$388,677,619	$429,678,343	($41,000,724)	-9.54%
	TOTAL	$471,734,229	$514,972,147	($43,237,918)	-8.40%
LARGE GENERAL SERVICE					
DEMAND		$289,068	$339,639	($50,571)	-14.89%
PROPANE		$0	$810	($810)	-100.00%
COMMODITY		$2,012,140	$2,196,917	($184,777)	-8.41%
	TOTAL	$2,301,208	$2,537,366	($236,158)	-9.31%
SMALL VOLUME DUAL FUEL					
COMMODITY		$31,943,376	$34,183,122	($2,239,746)	-6.55%
	TOTAL	$31,943,376	$34,183,122	($2,239,746)	-6.55%
LARGE VOLUME DUAL FUEL					
COMMODITY		$20,408,695	$21,961,458	($1,552,763)	-7.07%
	TOTAL	$20,408,695	$21,961,458	($1,552,763)	-7.07%

CenterPoint Energy
2017-2018 True-Up
Docket No. G008/AA-18-573
As Filed on September 4, 2018

			(1)	(2)	(3)	(4)
					(1) - (2)	(3) / (2)
					OVER/(UNDER)	OVER/(UNDER)
RECOVERY BY COMPONENT			RECOVERY	COST INCURRED	RECOVERY	RECOVERY
DEMAND	SVF		$83,056,610	$85,103,289	($2,046,679)	-2.40%
DEMAND	LGS		$289,068	$339,639	($50,571)	-14.89%
PROPANE	SVF		$0	$191,325	($191,325)	-100.00%
		TOTAL	$83,345,678	$85,634,253	($2,288,575)	-2.67%
COMMODITY	SVF		$388,677,619	$429,678,343	($41,000,724)	-9.54%
COMMODITY	LGS		$2,012,140	$2,196,917	($184,777)	-8.41%
COMMODITY	SVDF		$31,943,376	$34,183,122	($2,239,746)	-6.55%
COMMODITY	LVDF		$20,408,695	$21,961,458	($1,552,763)	-7.07%
		TOTAL	$443,041,830	$488,019,840	($44,978,010)	-9.22%
TOTAL DEMAND AND COMMODITY			$526,387,508	$573,654,093	($47,266,585)	-8.24%

Ten Year Summary of Gas-Cost Recovery:

Year ended 6/30	Present Year Percent Over/(Under) Recovery	Cumulative Percent Over/(Under) Recovery
2008-2009	-0.23%	
2009-2010	-1.26%	
2010-2011	-0.50%	
2011-2012	-3.15%	
2012-2013	-0.36%	
2013-2014	-10.47%	
2014-2015	-2.24%	
2015-2016	-2.34%	
2016-2017	-1.72%	
2017-2018	**-1.56%**	**-0.09%**
10-YEAR AVG	-2.38%	

Recovery by Class

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)	Present Year True-Up Over/(Under) Beginning Balance
Residential	$145,166,164	$145,073,531	$92,633	**0.06%**	$96,919
Commercial/Industrial Firm	$83,715,284	$84,679,680	($964,396)	**-1.14%**	$162,678
Demand Billed Demand	$1,782,129	$1,708,701	$73,428	**4.30%**	($1,438)
Demand Billed Commodity	$8,679,612	$9,257,228	($577,616)	**-6.24%**	$35,951
Small Interruptible	$6,506,639	$6,980,231	($473,592)	**-6.78%**	$20
Medium & Large Interruptible	$24,714,064	$27,160,537	($2,446,473)	**-9.01%**	$87,807
TOTAL	**$270,563,892**	**$274,859,908**	**($4,296,016)**	-1.56%	**$381,937**

	(6)	(7)	(8) (7)/(2)	(9)	(10)
	Prior Period Adj. Over/(Under)	Total Over/(Under) Collection	Cumulative %	Estimated Sales Therms	**True-Up Factors (Therms) (Refund)/Collection**
Residential	$1,781,765	$1,971,317	**1.36%**	369,851,661	**($0.00533)**
Commercial/Industrial Firm	$1,010,196	$208,478	**0.25%**	214,512,399	**($0.00097)**
Demand Billed Demand	$0	$71,990	**4.21%**	3,135,510	**($0.02296)**
Demand Billed Commodity	$187,222	($354,443)	**-3.83%**	29,653,570	**$0.01195**
Small Interruptible	$134,164	($339,408)	**-4.86%**	21,436,099	**$0.01583**
Medium & Large Interruptible	$555,693	($1,802,973)	**-6.64%**	84,800,441	**$0.02126**
TOTAL	**$3,669,040**	**($245,039)**	**-0.09%**	**720,254,170**	

Xcel Gas
2017-2018 True Up
Docket No. G002/AA-18-572
As Filed August 31, 2018

Recovery by Class		(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
Residential		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$31,874,122	$29,027,084	$2,847,038	9.81%
TU Sch. D, page 4	Commododity & Peak Shaving	$113,292,042	$116,046,447	($2,754,405)	-2.37%
	TOTAL	$145,166,164	$145,073,531	$92,633	0.06%
Commercial/Industrial Firm		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$18,085,118	$16,838,099	$1,247,019	7.41%
TU Sch. D, page 4	Commododity & Peak Shaving	$65,630,166	$67,841,581	($2,211,415)	-3.26%
	TOTAL	$83,715,284	$84,679,680	($964,396)	-1.14%
Demand Billed		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$1,782,129	$1,708,701	$73,428	4.30%
TU Sch. D, page 4	Commododity & Peak Shaving	$8,679,612	$9,257,228	($577,616)	-6.24%
	TOTAL	$10,461,741	$10,965,929	($504,188)	-4.60%
Small Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$6,506,639	$6,980,231	($473,592)	-6.78%
	TOTAL	$6,506,639	$6,980,231	($473,592)	-6.78%
Medium & Large Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$24,714,064	$27,160,537	($2,446,473)	-9.01%
	TOTAL	$24,714,064	$27,160,537	($2,446,473)	-9.01%

Recovery by Component		RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) (%)
Demand	Residential	$31,874,122	$29,027,084	$2,847,038	9.81%
Demand	Commercial/Industrial Firm	$18,085,118	$16,838,099	$1,247,019	7.41%
Demand	Demand Billed	$1,782,129	$1,708,701	$73,428	4.30%
	TOTAL DEMAND	$51,741,369	$47,573,884	$4,167,485	8.76%
Commodity	Residential	$113,292,042	$116,046,447	($2,754,405)	-2.37%
Commodity	Commercial/Industrial Firm	$65,630,166	$67,841,581	($2,211,415)	-3.26%
Commodity	Demand Billed	$8,679,612	$9,257,228	($577,616)	-6.24%
Commodity	Small Interruptible	$6,506,639	$6,980,231	($473,592)	-6.78%
Commodity	Medium & Large Interruptible	$24,714,064	$27,160,537	($2,446,473)	-9.01%
	TOTAL COMMODITY	$218,822,523	$227,286,024	($8,463,501)	-3.72%

Attachment G12
COMMODITY COSTS
Total Weighted Average Cost of Commodity
PGA Recovered Versus Actual Incurred [2]

PGA System	Recovered PGA Commodity Rate	**Rankings**	Difference Btwn Recovered PGA Commodity Rate ($/Mcf) And Mn Weighted Avg		Difference Btwn Recovered PGA Commodity Rate ($/Mcf) And Mn Non-Weighted Avg		Actual Annual Commodity Rate	**Rankings**	Difference Btwn Actual Annual Commodity Rate ($/Mcf) And Mn Weighted Avg		Difference Btwn Actual Annual Commodity Rate ($/Mcf) And Mn Non-Weighted Avg		Percent Over/(Under) Recovery	**Rankings**
	$/Mcf		$/Mcf	%	$/Mcf	%	$/Mcf		$/Mcf	%	$/Mcf	%		
Greater Minnesota	$ 3.1241	**4**	$ (0.0436)	-1.38%	$ 0.0615	2.01%	$ 3.2378	**3**	$ (0.2027)	-5.89%	$ (0.1364)	-4.04%	-3.51%	**1**
Great Plains***	$ 3.0781	**3**	$ (0.0896)	-2.83%	$ 0.0155	0.51%	$ 3.6461	**5**	$ 0.2055	5.97%	$ 0.2718	8.06%	-15.58%	**6**
MERC-Consolidated	$ 2.5403	**1**	$ (0.6275)	-19.81%	$ (0.5223)	-17.06%	$ 2.9324	**1**	$ (0.5081)	-14.77%	$ (0.4419)	-13.10%	-13.37%	**5**
MERC-NNG	$ 3.4421	**6**	$ 0.2744	8.66%	$ 0.3795	12.39%	$ 3.7923	**6**	$ 0.3518	10.22%	$ 0.4180	12.39%	-9.23%	**4**
CenterPoint Energy****	$ 3.2867	**5**	$ 0.1189	3.76%	$ 0.2241	7.32%	$ 3.6203	**4**	$ 0.1798	5.23%	$ 0.2461	7.29%	-9.22%	**3**
Xcel Gas	$ 2.9043	**2**	$ (0.2634)	-8.32%	$ (0.1583)	-5.17%	$ 3.0166	**2**	$ (0.4239)	-12.32%	$ (0.3576)	-10.60%	-3.72%	**2**
Weighted MN Average	**$ 3.1677**						**$ 3.4405**						**-7.93%**	
Non-Weighted MN Average	**$ 3.0626**						**$ 3.3743**						**-9.24%**	
Standard Deviation	**$ 0.3150**						**$ 0.3608**							

***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
2 The numbers reported in this table are from the Annual Automatic Adjustment filing submitted by each utility.
The numbers used and the detailed calculations are contained in Attachment G15.

Attachment G12a
Total System Gas Costs[2]

PGA System	PGA Recovered	Actual Total Gas Sales (MMBtu)	PGA Recovered ($/MMBtu)	Rankings	Difference Btwn PGA Recovered And Mn Weighted Avg		Difference Btwn PGA Recovered And Mn Non-Weighted Avg		Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)	Current-Period Actual Incurred Gas Cost ($/MMBtu)	Rankings	Difference Btwn Current-Period Actual Incurred Gas Cost And Mn Weighted Avg		Difference Btwn Current-Period Actual Incurred Gas Cost And Mn Non-Weighted Avg		Actual Over/(Under) ($/MMBtu)	Percent Over/(Under) Recovery
					$/MMBtu	%	$/MMBtu	%					$/MMBtu	%	$/MMBtu	%		
	(1)	(2)	(3) = (1)/(2)						(4)	(5)	(6) = (4)/(5)						(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota Gas	$ 5,416,510	1,433,861	$ 3.7776	**3**	$ (0.0607)	-1.58%	$ (0.0171)	-0.45%	$ 5,565,282	1,433,861	$ 3.8813	**3**	$ (0.1962)	-4.81%	$ (0.1441)	-3.58%	$ (0.1038)	-2.67%
Great Plains***	$ 15,195,404	3,780,874	$ 4.0190	**5**	$ 0.1807	4.71%	$ 0.2244	5.91%	$ 16,897,064	3,780,874	$ 4.4691	**5**	$ 0.3915	9.60%	$ 0.4436	11.02%	$ (0.4501)	-10.07%
MERC-Consolidated	$ 19,570,169	6,126,804	$ 3.1942	**1**	$ (0.6441)	-16.78%	$ (0.6004)	-15.82%	$ 20,787,490	6,126,804	$ 3.3929	**1**	$ (0.6847)	-16.79%	$ (0.6326)	-15.71%	$ (0.1987)	-5.86%
MERC-NNG**	$ 125,683,269	29,358,267	$ 4.2810	**6**	$ 0.4427	11.53%	$ 0.4864	12.82%	$ 132,619,114	29,358,267	$ 4.5173	**6**	$ 0.4397	10.78%	$ 0.4918	12.22%	$ (0.2362)	-5.23%
CenterPoint Energy****	$ 526,387,508	134,799,950	$ 3.9050	**4**	$ 0.0666	1.74%	$ 0.1103	2.91%	$ 572,097,914	134,799,950	$ 4.2441	**4**	$ 0.1665	4.08%	$ 0.2186	5.43%	$ (0.3391)	-7.99%
Xcel Gas	$ 270,563,892	75,343,865	$ 3.5911	**2**	$ (0.2473)	-6.44%	$ (0.2036)	-5.36%	$ 274,859,908	75,343,865	$ 3.6481	**2**	$ (0.4295)	-10.53%	$ (0.3774)	-9.37%	$ (0.0570)	-1.56%
Mn Weighted Average	**$ 962,816,752**	**250,843,621**	**$ 3.8383**						**$ 1,022,826,772**	**250,843,621**	**$ 4.0775**						**$ (0.2392)**	**-5.87%**
Mn Non-Weighted Average			**$ 3.7946**								**$ 4.0254**						**$ (0.2308)**	**-5.73%**
Standard Deviation			**$ 0.3745**								**$ 0.4582**							

**NOTE: As of July 1, 2017, MERC-AL was merged with the MERC-NNG PGA system.
***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
2 The numbers reported in this table are from the Annual Automatic Adjustment filing submitted by each utility.

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2017 - June 30, 2018

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		2016-2017	2017-2018			2016-2017	2017-2018			2016-2017	2017-2018			2016-2017	2017-2018		
Company	Tariff Rate Designation	Annual Customer Charge ($)	Annual Customer Charge ($)	$ Diff (2) - (1)	% Diff (3)/(1)	Average Combined Commodity and Demand Charges ($/Mcf)	Average Combined Commodity and Demand Charges ($/Mcf)	$ Diff (6) - (5)	% Diff (7)/(5)	Average Non-Gas Commodity Margin ($/Mcf)	Average Non-Gas Commodity Margin ($/Mcf)	$ Diff (10) - (9)	% Diff (11)/(9)	Average True-Up ($/Mcf)	Average True-Up ($/Mcf)	$ Diff (14) - (13)	% Diff (15)/(13)
Greater Minnesota Gas	RS-1	$102.00	$102.00	$0.00	0.00%	$4.7459	$3.9945	($0.7514)	-15.83%	$4.4433	$4.4433	$0.0000	0.00%	($0.0571)	$0.0185	$0.0756	-132.40%
Great Plains	N60	$84.00	$90.00	$6.00	7.14%	$4.6722	$4.2575	($0.4146)	-8.87%	$2.1292	$2.5259	$0.3966	18.63%	$0.0592	$0.1584	$0.0992	167.51%
MERC-CON	MERC000002	$130.94	$118.44	($12.50)	-9.55%	$3.6221	$2.6260	($0.9961)	-27.50%	$2.4031	$2.5594	$0.1563	6.50%	($0.0022)	($0.0652)	($0.0630)	2919.31%
MERC-NNG	MERC000001	$121.60	$118.44	($3.16)	-2.60%	$5.0810	$3.8981	($1.1828)	-23.28%	$2.4029	$2.5579	$0.1550	6.45%	($0.0058)	$0.0944	$0.1002	-1724.39%
CenterPoint Energy	Residential	$116.70	$125.25	$8.55	7.33%	$4.0764	$4.0443	($0.0321)	-0.79%	$2.2019	$2.2201	$0.0182	0.83%	$0.0414	$0.1415	$0.1001	241.79%
Xcel Gas	101	$108.00	$108.00	$0.00	0.00%	$4.4525	$4.1964	($0.2561)	-5.75%	$1.8591	$1.8591	$0.0000	0.00%	$0.0393	$0.0295	($0.0098)	-24.93%
MN NON-WEIGHTED AVERAGE		$102.53	$110.36	$7.82	7.63%	$4.45	$3.84	($0.6131)	-13.78%	$2.44	$2.69	$0.2568	10.53%	$0.0415	$0.0628	$0.0214	51.57%

*IPL and MERC-AL's partial year historical numbers are used for 2014-2015.
Previous reports used simple averages; current report uses weighted averages as provided by the utilities in response to Information Request 1.
The difference between using simple and weighted averages is not significant, however it more accurately reflects average costs throughout the year.

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2017 - June 30, 2018

		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)
		2016-2017	**2017-2018**			**2016-2017**	**2017-2018**			**2016-2017**	**2017-2018**			**2016-2017**	**2017-2018**		
Company	**Tariff Rate Designation**	**Average Total Cost of Gas ($/Mcf) (6)+(10)+(14)**	**Average Total Cost of Gas ($/Mcf) (6)+(10)+(14)**	**$ Diff (18) - (17)**	**% Diff (19)/(17)**	**Average Use (Mcf)**	**Average Use (Mcf)**	**Mcf Diff (22) - (21)**	**% Diff (23)/(21)**	**Total Average Customer Use (Mcf)**	**Total Average Customer Use (Mcf)**	**Mcf Diff (26) - (25)**	**% Diff (27)/(25)**	**Average Number of Customers**	**Average Number of Customers**	**Customer Diff (30) - (29)**	**% Diff (31)/(29)**
Greater Minnesota Gas	RS-1	$9.1321	$8.4563	($0.6758)	-7.40%	5.50	7.25	1.75	31.82%	66.00	87.00	21.00	31.82%	6,567	7,052	485.00	7.39%
Great Plains	N60	$6.8606	$6.9418	$0.0812	1.18%	5.98	7.05	1.08	17.99%	71.70	84.60	12.90	17.99%	8,333	8,382	49.08	0.59%
MERC-CON	MERC000002	$6.0230	$5.1202	($0.9029)	-14.99%	6.51	7.65	1.14	17.59%	78.07	91.80	13.73	17.59%	30,567	30,312	(255.08)	-0.83%
MERC-NNG	MERC000001	$7.4781	$6.5503	($0.9277)	-12.41%	6.44	7.63	1.19	18.51%	77.27	91.57	14.30	18.51%	170,602	171,573	971.25	0.57%
CenterPoint Energy	Residential	$6.3197	$6.4059	$0.0862	1.36%	6.75	7.90	1.15	17.04%	81.00	94.80	13.80	17.04%	776,257	787,172	10,915.00	1.41%
Xcel Gas	101	$6.3509	$6.0850	($0.2659)	-4.19%	6.67	7.58	0.92	13.75%	80.00	91.00	11.00	13.75%	418,450	421,994	3,544.00	0.85%
MN NON-WEIGHTED AVERAGE		$6.9282	$6.5932	($0.3350)	-4.83%	6.23	7.51	1.28	20.48%	74.81	90.13	15.32	20.48%	178,799	237,748	58,948.16	32.97%

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2017 - June 30, 2018

		(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)
		2016-2017	2017-2018			2016-2017	2017-2018			2016-2017	2017-2018		
Company	Tariff Rate Designation	Average Total Monthly Bill ($) [(2)/12]+[(18)*(22)]	Average Total Monthly Bill ($) [(2)/12]+[(18)*(22)]	$ Diff (34) - (33)	% Diff (35)/(33)	Average Total Annual Bill ($) (2)+[(18)*(26)]	Average Total Annual Bill ($) (2)+[(18)*(26)]	$ Diff (38) - (37)	% Diff (39)/(37)	Average Total Annual Bill at 140 Mcf/Year ($) (1)+[(18)*140]	Average Total Annual Bill at 140 Mcf/Year ($) (1)+[(18)*140]	$ Diff (42) - (41)	% Diff (43)/(41)
Greater Minnesota Gas	RS-1	$58.73	$69.81	$11.08	18.87%	$704.72	$837.70	$132.98	18.87%	$1,380.49	$1,285.88	-$94.61	-6.85%
Great Plains	N60	$47.99	$56.44	$8.45	17.60%	$575.91	$677.27	$101.37	17.60%	$1,044.49	$1,061.85	$17.36	1.66%
MERC-CON	MERC000002	$50.10	$49.04	-$1.06	-2.11%	$601.16	$588.47	-$12.69	-2.11%	$974.16	$835.26	-$138.90	-14.26%
MERC-NNG	MERC000001	$58.29	$59.85	$1.57	2.69%	$699.43	$718.25	$18.82	2.69%	$1,168.53	$1,035.49	-$133.04	-11.39%
CenterPoint Energy	Residential	$52.38	$61.04	$8.66	16.53%	$628.60	$732.53	$103.93	16.53%	$1,001.46	$1,022.08	$20.62	2.06%
Xcel Gas	101	$51.34	$55.14	$3.81	7.41%	$616.07	$661.73	$45.66	7.41%	$997.13	$959.90	-$37.23	-3.73%
MN NON-WEIGHTED AVERAGE		$51.52	$58.55	$7.04	13.66%	$618.22	$702.66	$84.44	13.66%	$1,072.48	$1,033.41	-$39.07	-3.64%

Attachment G14
Daily Delivery Variance Charges (DDVC)
Supporting Tables G22 and G23

Source IR 7

DDVC Volumes (MMbtu)

Company	Positive & Negative	punitive	total
Greater Minnesota	12,816	-	12,816
Great Plains	40,338	-	40,338
CPE	77,206	-	77,206
MERC-CON	-	-	-
Xcel Gas-MN	178,100	-	178,100
MERC-NNG	960	-	960
MN Totals	309,420	-	309,420

	DDVC ($)				Percent of Total Costs Incurred		
Company	Positive & Negative	punitive	total	Actual Incurred Gas Cost ($)	Positive & Negative	punitive	total
Greater Minnesota	$4,206	$1,220	$5,426	$5,565,282	0.0756%	0.0219%	0.0975%
Great Plains	$4,934	$0	$4,934	$16,897,064	0.0292%	0.0000%	0.0292%
CPE	$38,908	$0	$38,908	$572,097,915	0.0068%	0.0000%	0.0068%
MERC-CON	$0	$0	$0	$20,787,490	0.0000%	0.0000%	0.0000%
Xcel Gas-MN	$45,831	$0	$45,831	$274,859,909	0.0167%	0.0000%	0.0167%
MERC-NNG	$242	$0	$242	$132,619,114	0.0002%	0.0000%	0.0002%
MN Totals	$94,121	$1,220	$95,341	$1,022,826,774	0.0092%	0.0001%	0.0093%

Source: IR 7
Note: Xcel's and GP's charges are overrun charges on the Viking pipeline system rather than DDVCs on NNG's pipeline system.

Attachment G15
TOTAL COMMODITY COSTS 1
Rate Class: ALL CLASSES

PGA System	Actual Total Gas Sales (Mcf)	Recovered Annual PGA Commodity Costs ($)	Recovered PGA Commodity Rate ($/Mcf)	Actual Total Gas Sales (Mcf)	Actual Total Annual Commodity Costs ($)	Actual Annual Commodity Rate ($/Mcf)	% Change
	(1)	(2)	(3) = (2)/(1)	(4)	(5)	(6) = (5)/(4)	(7) = (3-6)/(6)
Greater Minnesota	1,433,861	$ 4,479,521	$ 3.1241	1,433,861	$ 4,642,607	$ 3.2378	-3.51%
Great Plains North	3,780,874	$ 11,637,852	$ 3.0781	3,780,874	$ 13,785,339	$ 3.6461	-15.58%
MERC-Consolidated****	6,126,804	$ 15,563,624	$ 2.5403	6,126,804	$ 17,966,249	$ 2.9324	-13.37%
MERC-NNG*****	29,358,267	$ 101,055,341	$ 3.4421	29,358,267	$ 111,335,435	$ 3.7923	-9.23%
CenterPoint Energy***	134,799,950	$ 443,041,830	$ 3.2867	134,799,950	$ 488,019,840	$ 3.6203	-9.22%
Xcel Gas	75,343,865	$ 218,822,523	$ 2.9043	75,343,865	$ 227,286,024	$ 3.0166	-3.72%
MN Weighted Average	250,843,621	$ 794,600,691	$ 3.1677	250,843,621	$ 863,035,494	$ 3.4405	-7.93%
MN Non-Weighted Average			$ 3.0626			$ 3.3743	-9.24%

***NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
****NOTE: MERC's four PGA systems (NMU, PNG, GL, VIK) were consolidated into two PGA systems (MERC-CON and MERC-NNG) effective July 1, 2013.
*****NOTE: MERC's purchased Interstate Power's Minnesota operations and created the MERC-AL PGA system, effective May 1, 2015.
The MERC-AL PGA system was merged with the MERC-NNG PGA system effective July 1, 2017.
1 Recovered and Actual Annual PGA Commodity Costs (columns 2 and 5) are from the Annual True-Up filings submitted by each utility.

Attachment G16
Current-Year Total System Demand and Commodity Costs1
Rate Class: ALL CLASSES

PGA System		PGA Recovered	Actual Total Gas Sales (MMBtu)		PGA Recovered ($/MMBtu)	**Rankings**		Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)		Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**		Actual Over(Under) ($/MMBtu)	Percent Over(Under) Recovery
		(1)	(2)		(3) = (1)/(2)			(4)	(5)		(6) = (4)/(5)			(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota	$	5,416,510	1,433,861	$	3.7776	**3**	$	5,565,282	1,433,861	$	3.8813	**3**	$	(0.1038)	-2.67%
Great Plains***	$	15,195,404	3,780,874	$	4.0190	**5**	$	16,897,064	3,780,874	$	4.4691	**5**	$	(0.4501)	-10.07%
MERC-Consolidated	$	19,570,169	6,126,804	$	3.1942	**1**	$	20,787,490	6,126,804	$	3.3929	**1**	$	(0.1987)	-5.86%
MERC-NNG**	$	125,683,269	29,358,267	$	4.2810	**6**	$	132,619,114	29,358,267	$	4.5173	**6**	$	(0.2362)	-5.23%
CenterPoint Energy	$	526,387,508	134,799,950	$	3.9050	**4**	$	572,097,914	134,799,950	$	4.2441	**4**	$	(0.3391)	-7.99%
Xcel Gas	$	270,563,892	75,343,865	$	3.5911	**2**	$	274,859,908	75,343,865	$	3.6481	**2**	$	(0.0570)	-1.56%
Mn Weighted Average	**$**	**962,816,752**	**250,843,621**	**$**	**3.8383**		**$**	**1,022,826,772**	**250,843,621**	**$**	**4.0775**		**$**	**(0.2392)**	**-5.87%**
Mn Non-Weighted Average				**$**	**3.7946**					**$**	**4.0254**		**$**	**(0.2308)**	**-5.73%**
Standard Deviation					**0.3745**						**0.4582**				

**NOTE: MERC merged its Albert Lea PGA system with its NNG PGA system as of July 1, 2017.
***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became NNG and Vik. area combined.
1 The numbers reported in this table are from the true ups filing submitted by each utility.
The numbers used and the detailed calculations are contained in Attachment G12a.

Attachment G17
Current-Year Total Demand and Commodity Costs 1
Rate Class: FIRM

PGA System	PGA Recovered	Actual Total Gas Sales (MMBtu)	PGA Recovered ($/MMBtu)	**Rankings**	Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)	Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**	Actual Over(Under) ($/MMBtu)	Percent Over(Under) Recovery
	(1)	(2)	(3) = (1)/(2)		(4)	(5)	(6) = (4)/(5)		(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota	$ 4,558,050	1,140,351	$ 3.9971	**4**	$ 4,685,793	1,140,351	$ 4.1091	**3**	$ (0.1120)	-2.73%
Great Plains-Consolidated**	$ 12,029,245	2,807,881	$ 4.2841	**5**	$ 13,326,147	2,807,881	$ 4.7460	**6**	$ (0.4619)	-9.73%
MERC-Consolidated*** 2	$ 17,609,150	5,376,452	$ 3.2752	**1**	$ 18,560,014	5,376,452	$ 3.4521	**1**	$ (0.1769)	-5.12%
MERC-NNG*** 2	$ 115,258,611	26,284,869	$ 4.3850	**6**	$ 120,937,956	26,284,869	$ 4.6010	**5**	$ (0.2161)	-4.70%
CenterPoint Energy*****	$ 474,035,437	118,629,199	$ 3.9959	**3**	$ 516,105,560	118,629,199	$ 4.3506	**4**	$ (0.3546)	-8.15%
Xcel Gas****	$ 239,343,189	64,334,499	$ 3.7203	**2**	$ 240,719,140	64,334,499	$ 3.7417	**2**	$ (0.0214)	-0.57%
Mn Weighted Average	**$ 862,833,682**	**218,573,251**	**$ 3.9476**		**$ 914,334,610**	**218,573,251**	**$ 4.1832**		**$ (0.2356)**	**-5.63%**
Mn Non-Weighted Average			**$ 3.9429**				**$ 4.1667**		**$ (0.2238)**	**-5.37%**

**NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
***NOTE: MERC's four PGA systems (NMU, PNG, GL, VIK) were consolidated into two PGA systems (MERC-CON and MERC-NNG) effective July 1, 2013.
The MERC-AL PGA system was merged with the MERC-NNG PGA system effective July 1, 2017.
****NOTE: Xcel Gas considers the LGS/Demand Billed customers Firm customers.
*****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005.
******NOTE: MERC's purchased Interstate Power's Minnesota operations and created the MERC-AL PGA system, effective May 1, 2015.
1 The numbers reported in this table are from the true up filings and utility AAA reports.
2 MERC's Interruptible numbers include the Joint customers since Joint customers are not considered firm on the peak day.

This Table was prepared as requested by Commission Staff (See Commission staff briefing papers of November 8, 2001 in Docket No. E,G999/AA-00-1027, page 31). Please keep in mind that the comparisions between the regulated utilities

Attachment G18
Current-Year Total Costs1
Rate Class: INTERRUPTIBLE

PGA System	PGA Recovered	Actual Total Gas Sales (MMBtu)	PGA Recovered ($/MMBtu)	**Rankings**	Actual Incurred Total Gas Cost	Actual Total Gas Sales (MMBtu)	Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**	Actual Over(Under) ($/MMBtu)	Percent Over(Under) Recovery
	(1)	(2)	(3) = (1)/(2)		(4)	(5)	(6) = (4)/(5)		(7) = (3) - (6)	(8) = (7)/(6)
Greater Minnesota	$ 858,460	293,510	$ 2.9248	**3**	$ 879,489	293,510	$ 2.9965	**2**	$ (0.0716)	-2.39%
Great Plains***	$ 3,166,159	972,993	$ 3.2540	**5**	$ 3,570,917	972,993	$ 3.6700	**5**	$ (0.4160)	-11.33%
MERC-Consolidated *	$ 1,961,019	750,352	$ 2.6135	**1**	$ 2,227,476	750,352	$ 2.9686	**1**	$ (0.3551)	-11.96%
MERC-NNG *	$ 10,424,658	3,073,398	$ 3.3919	**6**	$ 11,681,158	3,073,398	$ 3.8007	**6**	$ (0.4088)	-10.76%
CenterPoint Energy*****	$ 52,352,071	16,170,751	$ 3.2375	**4**	$ 55,992,354	16,170,751	$ 3.4626	**4**	$ (0.2251)	-6.50%
Xcel Gas****	$ 31,220,703	11,009,366	$ 2.8358	**2**	$ 34,140,768	11,009,366	$ 3.1011	**3**	$ (0.2652)	-8.55%
Mn Weighted Average	**$ 99,983,070**	**32,270,370**	**$ 3.0983**		**$ 108,492,162**	**32,270,370**	**$ 3.3620**		**$ (0.2637)**	**-7.84%**
Mn Non-Weighted Average			**$ 3.0429**				**$ 3.3332**		**$ (0.2903)**	**-8.71%**

*NOTE: MERC's Interruptible numbers include the joint customers since Joint customers are not considered firm on the peak day.
The MERC-AL PGA system was merged with the MERC-NNG PGA system effective July 1, 2017.
***NOTE: As of July 1, 2017, Great Plains merged its North and South PGA systems into one Consolidated PGA system.
****NOTE: Xcel Gas considers the LGS/Demand Billed customers Firm customers.
*****NOTE: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became NNG and Vik. area combined.
1 The numbers reported in this table are from the true up filings and utility AAA reports.

This Table was prepared as requested by Commission Staff (See Commission staff briefing papers of November 8, 2001 in Docket No. E,G999/AA-00-1027, page 31).

Attachment G19
Lost-and-Unaccounted-for Gas
Supporting Table G29

SOURCE: IR 10

Utility Name	Purchased Gas (Mcf)	Purchased Gas Adjustments (Mcf)	Total Gas Purchased (Mcf)	Customer Use Gas (Mcf)	Company Use Gas (Mcf)	Consumed Gas Adjustments (Mcf)	Total Consumed Gas (Mcf)	Lost and Unaccounted Gas (Mcf)	Percent Unaccounted for Gas lost (found)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			(3)=(1)+(2)				(7)=(4)+(5)+(6)	(8)=(3)-(7)	(9)=[(8)/(3)]
Greater Minnesota	1,452,311	0	1,452,311	1,433,861	16,481	0	1,450,342	1,969	0.14%
Great Plains total co. #	3,968,554	(87,329)	3,881,225	3,780,874	0	50,785	3,831,659	49,566	1.28%
MERC-Consolidated **	6,090,351	50	6,090,401	6,126,803	14,627	0	6,141,430	(51,029)	-0.84%
MERC-NNG **	28,843,734	144,476	28,988,210	29,358,267	36,261	0	29,394,528	(406,318)	-1.40%
CenterPoint Energy	138,596,920	(317,427)	138,279,493	135,601,194	112,547	0	135,713,741	2,565,752	1.86%
Xcel Gas Mn jurisdiction *	76,098,886	686,761	76,785,647	75,334,374	9,491	0	75,343,865	1,441,782	1.88%
Statewide Totals	255,050,756	426,531	255,477,287	251,635,373	189,407	50,785	251,875,565	3,601,722	1.41%

Great Plains states that its Company use gas volumes are included in the Customer Use Gas column. GP's IR 16 states volumes represent estimated calendar month sales and the true-up volumes represent billed sales volumes.
* Xcel's LNG & propane purchases reported in Purchased Gas Adjustments, column (2).
** MERC reports its Purchased Gas in column (1) net of Adjustments in column (2) and Company Use Gas (5).

Attachment G20
Supporting Schedule to Tables G19 and G20

	Firm Design Day Demand (Mcf) (1)	Firm Design Day Deliverability **w/ Peak-Shaving** (Mcf) (2)	Actual Peak Day Date (Mcf) (3)	Design-Day Customer Numbers (4)	Actual Firm Peak Day Usage (Mcf) (5)	Annual Firm Throughput (Mcf) (6)	Design-Day Use Per Customer (7)	Peak-Day Use Per Design-Day Customer (8)	Annual Firm Load Factor (9)	Reserve Margin (10)	Annual Firm Requirement % (11)
Source:	**IR#2**	**IR#2**	**IR#3**	**IR#2**	**IR#3**	**IR#2**	**(7)=(1)/(4)**	**(8)=(1)/(5)**	**(9)=((6)/365)/(5)**	**(10)=((2)-(1))/(1)**	**(11)=(5)/(2)**
Greater Minnesota	11,896	12,609	12/31/17	8,113	10,360	1,140,351	1.4663	1.1483	30.16%	5.99%	82.2%
Great Plains #	32,733	34,445	01/04/18	23,997	28,641	3,109,853	1.3640	1.1429	29.75%	5.23%	83.1%
CenterPoint Energy	1,357,000	1,409,596	12/31/17	866,725	1,089,622	118,834,104	1.5657	1.2454	29.88%	3.88%	77.3%
MERC-CON	56,470	57,949	12/30/17	35,653	46,438	4,825,697	1.5839	1.2160	28.47%	2.62%	80.1%
Xcel Gas (Mn JURISDICTION)	730,147	776,298	12/26/17	457,769	553,667	72,593,858	1.5950	1.3187	35.92%	6.32%	71.3%
MERC-NNG	273,842	266,317	12/31/17	198,628	233,945	24,507,563	1.3787	1.1705	28.70%	-2.75%	87.8%
Totals	**2,462,088**	**2,557,214**		**1,590,885**	**1,962,673**	**225,011,426**	**1.5476**	**1.2545**	**31.41%**	**3.86%**	76.8%
TOTAL prior year		2,505,289									
Change from prior year		51,925									

Includes Wahpeton, North Dakota.
NOTE: Xcel's reports Mn Jurisdiction in IR 2 and 3 and MN + ND in IR 4.

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Review of 2017-2018 Annual Automatic Adjustment Reports and True-Up Filings

Docket No. G999/AA-18-374; G011/AA-18-489; G011/AA-18-490; G022/AA-18-563; G004/AA-18-567; G002/AA-18-572; and G008/AA-18-573

Dated this 25th day of April 2019

/s/Sharon Ferguson

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Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-567_AA-18-567

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_18-572_AA-18-572
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-572_AA-18-572
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_18-572_AA-18-572
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-572_AA-18-572
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_18-572_AA-18-572
Steven	Clay	Steven.Clay@CenterPointEnergy.com	CenterPoint Energy Minnesota Gas	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-572_AA-18-572
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-572_AA-18-572
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_18-572_AA-18-572
Seth	DeMerritt	Seth.DeMerritt@wecenergygroup.com	MERC (Holding)	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_18-572_AA-18-572
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_18-572_AA-18-572

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-572_AA-18-572
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_18-572_AA-18-572
Brian	Gardow	bgardow@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-572_AA-18-572
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_18-572_AA-18-572
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_18-572_AA-18-572
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Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-572_AA-18-572
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 South Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-572_AA-18-572
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_18-572_AA-18-572

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-572_AA-18-572
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_18-572_AA-18-572
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-572_AA-18-572
Lisa	Peterson	lisa.r.peterson@xcelenergy.com		Xcel Energy 414 Nicollet Mall - 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-572_AA-18-572
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_18-572_AA-18-572
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Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_18-572_AA-18-572
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_18-572_AA-18-572
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Mary	Wolter	mary.wolter@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_18-572_AA-18-572

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-573_AA-18-573
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-573_AA-18-573
Seth	DeMerritt	Seth.DeMerritt@wecenergygroup.com	MERC (Holding)	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_18-573_AA-18-573
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_18-573_AA-18-573
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_18-573_AA-18-573
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_18-573_AA-18-573
Brian	Gardow	bgardow@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-573_AA-18-573
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_18-573_AA-18-573

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Roger	Leider	roger@mnpropane.org	Minnesota Propane Association	PO Box 220 209 N Run River Dr Princeton, MN 55371	Electronic Service	No	OFF_SL_18-573_AA-18-573
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Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_18-573_AA-18-573
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Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_18-573_AA-18-573
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	Yes	OFF_SL_18-573_AA-18-573
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_18-573_AA-18-573
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	PO Box 68 202 South Main Street Le Sueur, MN 56058	Electronic Service	No	OFF_SL_18-573_AA-18-573
Lisa	Peterson	lisa.r.peterson@xcelenergy.com		Xcel Energy 414 Nicollet Mall - 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_18-573_AA-18-573
Catherine	Phillips	catherine.phillips@we-energies.com	We Energies	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_18-573_AA-18-573
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_18-573_AA-18-573
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Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-573_AA-18-573
Jonathan	Wolfgram	Jonathan.Wolfgram@state.mn.us	Office of Pipeline Safety	Minnesota Department of Public Safety 445 Minnesota Street Suite 147 St. Paul, MN 55101-1547	Electronic Service	No	OFF_SL_18-573_AA-18-573

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Scott	Zemke	szemke@capsh.org	Community Action Partnership	of Suburban Hennepin 8800 Highway 7, Ste. 401 St. Louis Park, MN 55426	Electronic Service	No	OFF_SL_18-573_AA-18-573