COMMERCE DEPARTMENT

April 26, 2022

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

RE: **Review of 2018-2019 Annual Automatic Adjustment Reports**
Docket No. G999/AA-19-401 and Natural Gas Utilities' 2018-2019 Purchased Gas Adjustment (PGA) True Up Filings (see attached list)

Dear Mr. Seuffert:

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 2018-2019 Annual Automatic Adjustment Reports* (FYE19 AAA Report) for regulated natural gas utilities in Minnesota.

The Department is available should the Minnesota Public Utilities Commission have any questions about the FYE19 AAA Report provided herein.

Sincerely,

/s/ GEMMA MILTICH
Financial Analyst, CPA
Division of Energy Resources

GM/ja
Attachments

Docket Numbers for 2018-2019 Gas Utility PGA True Up Filings

Docket No. G004/AA-19-555	Greater Minnesota Gas, Inc.
Docket No. G022/AA-19-542	Great Plains Natural Gas Company
Docket No. G008/AA-19-556	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas
Docket No. G011/AA-19-518	Minnesota Energy Resource Corporation (MERC) Consolidated PGA system
Docket No. G011/AA-19-517	Minnesota Energy Resource Corporation (MERC) Northern Natural Gas PGA system
Docket No. G002/AA-19-551	Northern States Power Company d/b/a Xcel Energy

Review of the 2018-2019 Annual Automatic Adjustment Reports

Submitted to the

Minnesota Public Utilities Commission

Docket No. G999/AA-19-401

April 26, 2022

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EXECUTIVE SUMMARY – NATURAL GAS UTILITIES

Minnesota Rules 7825.2800 through 7825.2830 require that public utilities using automatic adjustments to recover energy costs file annual reports regarding the operation of these automatic adjustments. The reports provide an opportunity for the Minnesota Public Utilities Commission (Commission) to verify whether utilities have calculated their rate adjustments properly and implemented these rates in a timely manner. The Minnesota Department of Commerce, Division of Energy Resources' (Department's) review of the current year, 2018-2019 (FYE19), filings, built on our experience gained from prior year AAA reports and was informed by our ongoing assessment of the utilities' automatic adjustment filings throughout the reporting period. The Department's FYE19 Annual Automatic Adjustment natural gas report (FYE19 AAA Report) includes analyses of:

- FYE19 automatic adjustment charge calculations, filed pursuant to Minnesota Rule 7825.2810

- Filings to reconciling or "truing up" the difference between revenues collected and actual gas costs incurred by the utilities, as required by Minnesota Rules 7825.2910 and 7825.2700

- Annual reporting requirements pursuant to Minnesota Rules 7825.2810 - 7825.2910 and as ordered by the Commission

- Supplemental data submitted by the utilities in response to Department information requests (IRs)

In the final section of the instant FYE19 AAA Report, the Department provides conclusions and makes specific recommendations to the Commission on the current period's AAA filings, as submitted by the following utilities:

- Greater Minnesota Gas, Inc. (Greater Minnesota or GMG)
- Great Plains Natural Gas Company (Great Plains)
- Minnesota Energy Resources Corp. (MERC) [1]
- CenterPoint Energy Minnesota Gas (CenterPoint or CPE)
- Northern States Power Company d/b/a Xcel Energy - Gas Utility (Xcel Gas or Xcel)

Recovery of energy costs represents an important component in the rates natural gas customers pay. Included in gas utility rates is a true up reflecting the difference between the actual costs the utilities incur and the actual revenues they recover; these true ups are based the last year's revenues and

[1] 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 *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.

costs. 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. Because customers leave and join the utility's system over time, the specific mix of customers on the utility's system likely to changes somewhat from year to year. Therefore, it is probable that some mismatch exists between the specific mix of customers receiving gas service in a given fiscal year and the mix of customers to which the refund or charge associated with the prior year's true up is assigned in subsequent years. While it is not feasible to eliminate such mismatches completely, it is essential that utilities attempt to minimize both over- and under-recoveries to avoid creating substantial inequities among ratepayer generations.

In FYE19, natural gas prices were slightly higher on average than prices during FYE18. The average FYE19 price was just above $3 per Mcf and rose to over $4 per Mcf in November and December 2018. Price per Mcf hovered near $3 for most of the reporting period. The Henry Hub price[2] in FYE19 ranged between $2.27 and $4.70, beginning the reporting period at about $2.90 per Mcf in July 2018 and ending the reporting period around $2.42 per Mcf in June 2019.

Several factors could explain why prices in FYE19 increased slightly compared to the prior year. First, weather in Minnesota was colder than normal in FYE19, putting upward pressure on gas prices during the heating season. Second, storage levels in the months leading up to the 2018-19 heating season were at 3.198 Bcf, the lowest level since 2005, and, despite FYE19 net withdrawals from storage being 5 percent below the five-year withdrawal average, end-of-heating-season storage levels were at their lowest since 2014; [3] the combination of low storage levels and an early, colder-than-normal start to the heating season in FYE19 may have contributed to the higher market prices seen in the first half of the heating season (November and December 2018). Third, natural gas consumption and production reached record levels in 2018. Production grew steadily over the year, due especially to production in the Appalachian Basin, Permian Basin, and the Haynesville shale formation. Consumption met the growth in production by increasing across industrial, residential, and commercial sectors.[4] These 2018 record consumption levels were topped when a polar vortex covered much of the lower 48 states in January 2019. The January 2019 polar vortex especially impacted the Midwest, which saw temperatures 25°F or more below normal for three consecutive days. This cold weather caused some delivery-day gas price increases, but, due at least in part to gains in natural gas production, the price spikes were less extreme than in other historical cold weather events. Market hubs in the Midwest and Northeast saw an increase in spot market prices the day before the polar vortex (January 28), with prices returning to near normal the day after the event (February 1).[5]

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[2] 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).

[3] EIA Natural Gas Weekly Update, April 10, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_11/.

[4] EIA Natural Gas Weekly Update, January 10, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/01_10/#itn-tabs-2.

[5] EIA Natural Gas Weekly Update, February 7, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/02_07/.

Gas price volatility for most of 2018 was moderate due to the corresponding record natural gas production. However, NYMEX near-month natural gas futures price volatility increased notably in November and December 2018, coinciding with the historically low pre-heating season gas storage and growing natural gas consumption that outpaced production levels at the time. The relatively high consumption level during this time can be attributed to the colder-than-normal conditions, high levels of net natural gas exports, and the growing use of natural gas in the electric sector. [6]

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, 51 percent of U.S. natural gas processing capacity is concentrated along the Gulf coast, making hurricanes an ongoing concern of market interruption.[7] During FYE19, there were several interruptions in natural gas production due to storms, as discussed in more detail in a later section of this Report.

[6] EIA Natural Gas Weekly Update, December 20, 2018:
https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2018/12_20/.
[7] https://www.eia.gov/special/gulf_of_mexico/

I. BACKGROUND

Minnesota Rule 7825.2810, Subparts 1 and 2 contain the following requirements for gas utility AAA filings:

<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
- Paragraph C - Billing adjustment amounts
- Paragraph D - Total cost of gas
- Paragraph E - Revenues collected
- Paragraph F - Supplier refunds received
- 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 - Level of customer-owned gas volumes delivered through the utility's system
- Paragraph D - A brief explanation of deviations between gas-cost recovery and actual cost

A. NATURAL GAS PRICES

In FYE19, natural gas prices were slightly higher on average than prices during FYE18. Overall, Henry Hub prices remained relatively steady throughout FYE19, hovering at around $3 per Mcf, and ranging from $2.27 to $4.70 per Mcf (beginning at around $2.90 per Mcf in July 2018 and ending at approximately $2.42 per Mcf in June 2019). Notable spikes in Henry Hub prices occurred during November and December 2018, when prices rose to over $4 per Mcf (up to $4.70 per Mcf) for about five weeks.

In FYE19, the price of residential propane in Minnesota ranged from $1.54-$1.64 per gallon ($17.45-$18.59 per Mcf), a smaller price range than FYE18, during which propane was between $1.58-$1.83/gallon ($17.91-$20.74 per Mcf).[8] Propane prices continued in FYE19 to be high compared to the cost of natural gas.

[8] 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 and one Mcf equals 10.37 therms. To find the price of propane per Mcf, multiply the price per gallon by (10.37 / 0.915).

B. WEATHER

Compared to 30-year normal weather,[9] the weather in the Minnesota area for FYE19 was generally colder than normal. The colder-than-normal annual weather ranged from approximately 0.04 percent colder at the Duluth weather station to approximately 10.79 percent colder in Rochester. The heating season (November 2018 through March 2019) was also colder than normal compared to 30-year normal weather. The colder-than-normal heating season weather ranged from approximately 2.26 percent colder at the Duluth weather station to approximately 10.38 percent colder in Rochester.

According to Northern Natural Gas Company's (NNG) April 2019 *Northern Notes*, the FYE19 heating season was colder than normal for four out of the five winter months, with the heating season overall being 13 percent colder than normal. This colder-than-average heating season followed a mix of warmer-than-average and colder-than-average heating seasons over the previous five years. NNG experienced its top three market area[10] peak delivery days in January 2019. The previous highest recorded market area peak delivery was December 26, 2017, when the market area delivery measured 5.221 Bcf. On January 29, 30, and 31, 2019, the market area delivery averaged 5.460, 5.621, and 5.327 Bcf, respectively. In the FYE19 heating season, NNG recorded five of its top ten highest daily deliveries, all greater than 5.0 Bcf. NNG delivered 4.0 Bcf per day or more to its market area on 50 days of the FYE19 heating season, compared to 35, 20, and 13 days during the FYE18, FYE17, and FYE16 heating seasons, respectively.

During FYE19, there were two relatively short-lived interruptions in natural gas production due to storms. Tropical Storm Gordon impacted natural gas production in the Gulf of Mexico for several days at the beginning of September 2018, at one point shutting down approximately nine percent of daily natural gas output in the area.[11] For a few days in October 2018, Hurricane Michael reduced daily natural gas production in the Gulf of Mexico by nearly a third; for example, on October 9, 2018 (during Hurricane Michael), drillers pulled just 2.2 Bcf of natural gas from the Gulf of Mexico's offshore wells, compared to the approximately 3.4 Bcf pulled per day the week before.[12] NYMEX price volatility remained relatively low, with prices hovering a little over $3 per Mcf, over the several weeks in September and October following each of these storms. This relatively low volatility in prices was likely because the FYE19 production disruptions were minor compared to domestic production levels. Over the last several years, the U.S. has rapidly increased its natural gas export levels, a pattern that continued during

[9] Based on weather data from 1981 through 2010.
[10] NNG's market area refers to NNG's service territory north of Demarcation, KS.
[11] Thomson Reuters, September 4, 2018, *Tropical Storm Gordon Shuts 9 Percent of Oil Output in Gulf of Mexico*: https://www.reuters.com/article/us-storm-gordon-production/tropical-storm-gordon-shuts-9-percent-of-oil-output-in-gulf-of-mexico-idUSKCN1LK2CK
[12] Thomson Reuters, October 10, 2018, *Hurricane Knocks Out 42 Percent of U.S. Gulf of Mexico Oil Output*: https://www.reuters.com/article/us-storm-michael-energy/hurricane-knocks-out-42-percent-of-u-s-gulf-of-mexico-oil-output-idUSKCN1MK1YN

FYE19. For example, LNG exports in the first quarter of 2019 averaged 4.0 Bcf/d, 1.0 Bcf/d higher than the annual average in 2018.[13]

C. GAS UTILITIES SUMMARY

In our review of the gas utilities' AAA filings, the Department worked to identify/assess (1) systematic patterns of over- or under-recoveries over time, (2) incorrect calculations of annual true up adjustment factors, (3) the utilities' compliance with AAA filing requirements, and (4) additional issues that may warrant Commission attention.

Because customers leave and join the utility's system over time, the specific mix of customers on the utility's system likely changes somewhat from year to year. Therefore, it is probable that some mismatch exists between the specific mix of customers receiving gas service in a given fiscal year and the mix of customers to which the refund or charge associated with the prior year's true up is assigned in subsequent years. Gas costs generally comprise the largest component of the rates natural gas customers pay, so, while it is not feasible to eliminate such mismatches completely, it is essential that utilities attempt to minimize both over- and under-recoveries to avoid creating substantial inequities among ratepayer generations.[14] An over-recovery for a given customer class in one year results in an offsetting decrease in the rates assigned to that customer class in the following year, and an under-recovery in one year increases rates in the subsequent year. The following table summarizes the fuel cost recovery during FYE19 for the gas utilities.

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[13] EIA Natural Gas Weekly Update, June 13, 2019: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/06_13/

[14] As discussed further in Section II, CenterPoint and Xcel apply a monthly demand adjustment to their demand cost recovery rates in order to match costs better within the true up year.

Table G1:[15] Summary of Gas Utilities' Annual Demand & Commodity Cost Recovery for FYE19[16]

Utility/System	*Gas Cost Recovered*	*Gas Cost Incurred*	*Over/(Under) Recovery*	*Over/(Under) Recovery*
GMG	$6,079,223	$6,025,911	$53,312	0.88%
Great Plains	$18,701,798	$18,070,263	$631,535	3.49%
MERC-CON	$25,307,737	$24,090,033	$1,217,704	5.05%
MERC-NNG[17]	$144,460,394	$135,435,851	$9,024,543	6.66%
CenterPoint	$579,532,137	$586,074,385	$(6,542,248)	(1.12%)
Xcel Gas	$315,460,340	$319,749,687	$(4,289,347)	(1.34%)
MN Total	$1,089,541,629	$1,089,446,130	$95,499	0.01%[18]

As shown in Table G1, the six PGA systems[19] experienced a mix of over/under-recovered gas costs (demand and commodity), ranging from an over-recovery of 6.66 percent for MERC-NNG to an under-recovery of 1.34 percent for Xcel. The $1,089,446,130 of total gas cost incurred for FYE19 represents an increase of approximately 6.5 percent from the $1,022,826,772 of total gas costs incurred in FYE18.

The following table compares the total FYE19 gas costs incurred to the nominal total gas costs in past reporting periods.

[15] The information for Table G1 can be found in each of the utilities' True Up Reports, which are shown in 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 Minnesota weighted-average amount is calculated by dividing the total over-recovery amount by the total gas costs incurred.

[19] The Department notes that "gas utility" and "PGA system" are, at times, interchangeable in the instant FYE19 AAA Report.

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

Reporting Period	*Annual Gas Cost Incurred*	*Percentage of Increase/ (Decrease) Between Prior Year and FYE19*
FYE19	$1,089,446,130	
FYE18	$1,022,826,772	7%
FYE17	$862,350,817	26%
FYE16	$730,948,119	49%
FYE15	$1,140,929,250	(5%)
FYE14	$1,659,257,488	(34%)
FYE13	$1,063,629,628	2%
FYE12	$899,685,483	21%
FYE11	$1,228,496,903	(11%)
FYE10	$1,290,861,146	(16%)

The total cost of gas for FYE19, $1,089,446,130, was near the ten-year (2010 – 2019) annual gas cost average of $1,098,843,174.

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

Table G2: Percentage of Over/(Under) Recovery FYE10-FYE19[20]

	GMG	*Great Plains*			*MERC*			*CenterPoint*	*Xcel Gas*
		North	*South*	*Con[21]*	*CON*	*NNG*	*AL[22]*		
FYE10	(5.18)	(3.57)	(2.62)		(2.09)	(1.25)		(3.96)	(1.26)
FYE11	(3.92)	0.45	(1.95)		2.00	2.58		(0.66)	(0.50)
FYE12	0.58	(7.83)	(4.73)		(2.15)	(6.19)		(4.68)	(3.15)
FYE13	1.46	(3.66)	(1.86)		2.82	0.08		(0.84)	(0.36)
FYE14	(0.27)	(12.09)	(13.57)		(9.25)	(6.45)		(6.88)	(10.47)
FYE15	0.98	1.57	(3.00)		(3.91)	1.90	(27.03)	1.44	(2.24)
FYE16	1.32	(1.66)	(2.48)		0.72	(2.60)	(3.47)	(2.53)	(2.34)
FYE17	(0.91)	(1.00)	(4.48)		1.41	(2.97)	(4.45)	(3.71)	(1.72)
FYE18	(2.67)			(10.07)	(5.86)	(5.23)		(7.97)	(1.56)
FYE19	0.88			3.49	5.05	6.66		(1.11)	(1.34)
Average	(0.77)	(3.47)	(4.34)	(3.29)	(1.13)	(1.35)	(11.65)	(3.09)	(2.49)
Cumulative[23]	1.30			4.13	5.38	7.02		(0.33)	(1.32)

As shown in Table G2, the PGA systems experienced a mix of cumulative under/over-recoveries during FYE19. The utilities' 2020 true up factors are calculated based on the cumulative amount of under/over-recovery at the end of FYE19. The ten-year averages (FYE10 through FYE19) show an under-recovery for each gas utility. The Department includes an analysis of the over/under-recovery for each utility later in the instant FYE19 AAA Report.

The following Table G3 provides a summary of the current period's over/under-recoveries and illustrates over/under-recoveries for firm and interruptible classes as a whole and by pipeline system for equivalent PGA systems during the FYE19 true up period.

[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] 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. Effective July 1, 2017, MERC merged its Albert Lea PGA system with its NNG PGA system per Docket No. G011/GR-15-736.
[23] The figures for this row are included in Department Attachment G5 through G11 in each of the utility's True Up Reports. The cumulative over/under-recovery is a calculation based on prior years' true ups and the present year's true up.

Table G3: FYE19 Percentage of Over/(Under)-Recovery by Firm and Interruptible Classes

Utility/System	*Firm*	*Interruptible*[24]	*Total*
GMG	1.92%	(5.55%)	0.88%
Great Plains	3.51%	3.42%	3.49%
MERC-CON	5.69%	(1.27%)	5.05%
MERC-NNG	7.76%	(5.53%)	6.66%
CenterPoint	(1.11%)	(1.16%)	(1.12%)
Xcel Gas	(0.71%)	(6.02%)	(1.34%)
MN Weighted Average	0.37%	(3.15%)	0.01%

Table G3 shows that the PGA systems experienced a mix of over/under-recovery, and only MERC had over/under-recoveries of more than five percent.

D. IMPACTS ON 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/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
- The “three-cent rule” from Minnesota Rule 7825.2700, Subpart 3

The Department provides the following discussion on each of these factors:

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.[25]

The Department uses data from seven area weather stations to review weather relevant to Minnesota’s utilities.[26] The FYE19 data from these weather stations are summarized in Table G4 and

[24] MERC's interruptible figures include the Joint customers’ firm requirements since the Joint customers are not considered firm on the peak day.
[25] 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.
[26] 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).

in more detail in Attachment G1. Compared to 30-year normal weather from 1981 to 2010,[27] the annual weather in Minnesota for FYE19 was colder than normal across the state. The FYE19 weather in Minnesota was as follows:

Table G4: FYE19 Weather in Minnesota

Weather Station	*Deviation from Normal**
Duluth	0.04%
International Falls	5.08%
Fargo, ND	11.45%
St. Cloud	8.49%
Minneapolis/St. Paul	5.86%
Rochester	10.79%
Sioux Falls, SD	2.87%

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

The weather in Minnesota for the heating season from November to March was also colder than normal compared to 30-year normal weather. The heating season weather was as follows:

Table G5: FYE19 Winter Weather in Minnesota

Weather Station	*Deviation from Normal*
Duluth	2.26%
International Falls	4.59%
Fargo, ND	1.20%
St. Cloud	7.79%
Minneapolis/St. Paul	5.53%
Rochester	10.38%
Sioux Falls, SD	3.78%

Recovery of demand costs is affected by weather because utilities calculate the demand portion of their rates based on test-year or historical weather-normalized firm sales, but they recover demand costs on each unit of firm gas actually sold. Therefore, when weather is warmer than normal, causing customers to use less gas, utilities may under-recover demand costs. Conversely, utilities may over-recover demand costs when customers use more gas during colder-than-normal periods.

[27] 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.

Due to the colder-than-normal weather experienced during the winter, all else being equal, utilities would have over-recovered demand costs in FYE19 (interruptible customers are not charged for demand costs). All the PGA systems over-recovered demand costs for FYE19, except CenterPoint. Table G6 summarizes the FYE19 demand cost over/under-recovery:

Table G6: FYE19 Over/(Under)-Recovery of Demand Costs as Filed[28]

GMG	10.80%
Great Plains	10.27%
MERC-CON	43.42%
MERC-NNG	48.44%
CenterPoint	(4.14%)
Xcel Gas	6.38%

Recovery of commodity costs is affected by weather and market price fluctuations. The commodity portion of natural gas rates charged in a given month is generally based on price estimates made during the week prior to the beginning of that month. Therefore, an unexpected cold period during the middle of a month, following normal weather in the last week in the preceding month, typically leads 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 typically leads to an over-recovery of commodity costs if actual commodity gas costs correspondingly decline. 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.

Multiple inversely related factors affected commodity costs in FYE19. As discussed, weather for the FYE19 was substantially colder than normal, putting upward pressure on commodity prices. The increasing demand for natural gas has also put upward pressure on commodity prices. However, natural gas production over the last several years has proven tcapable of keeping up with rising demand, and this production flexibility has kept prices relatively stable in recent years. Despite increasingly prevalent weather extremes making it difficult to predict seasonal commodity prices, the utilities' over/under-recovery of commodity prices in FYE19 were relatively minor. Each PGA system over/(under) recovered its commodity costs by the percentages shown in the following table.

[28] 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.

Table G7: FYE19 Over/(Under)-Recovery of Commodity Costs as Filed[29]

GMG	(0.94%)
Great Plains	1.81%
MERC-CON	(0.87%)
MERC-NNG	(0.79%)
CenterPoint	(0.95%)
Xcel Gas	(2.72%)

Calculation of the Monthly Volumetric Demand Cost Recovery Rate – In general, demand costs are the costs of reserving pipeline capacity to transport firm gas supplies.[30] Pursuant to Minnesota Rules 7825.2910, Subpart 2, gas utilities must file a petition to increase or decrease demand, redistribute demand percentages among classes, or exchange one form of demand for another. The petition must include a description of the factors contributing to the need for the demand change, the utility's design-day demand by customer class, and the change in design-day demand.

Since the current non-gas base rate for most gas 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.

The demand cost recovery rate is calculated in the monthly PGA by applying Federal Energy Regulatory Commission (FERC)-approved natural gas pipeline rates[31] to the Commission-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.[32] Further, sales are

[29] Except for CenterPoint, the percentages include revenue such as balancing penalty revenue. Additionally, commodity costs include storage and balancing costs.
[30] 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.
[31] If the natural gas pipeline is intrastate, then the Commission-approved rates apply.
[32] 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
- natural gas pipeline rates approved by FERC

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.[33] This under-recovery occurs because the winter months are when the greatest percentage of cost recovery generally occurs.

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 utility credits the monthly PGA and/or the annual true up, thereby reducing the demand costs 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.

Deviations Between Forecasted and Actual Sales Volumes and Prices – For commodity costs, a common causes of over/under-recovery are (1) the deviation between monthly forecasts and actual sales volumes and (2) 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.

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. Therefore, the utility must bill the customer based on an estimate of the consumption that took place during each PGA period. Because this prorated bill will not exactly match the true consumption that took place each month, except by coincidence, over- or under-recoveries typically result.

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 the listed factors may affect gas costs and recovery of gas costs for Minnesota's gas utilities. The following section highlights the individual gas utility true up results for FYE19 and, as applicable, addresses the factors discussed in the preceding list along with other notable factors that contributed to the FYE19 over/under-recoveries.

[33] 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.

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

The gas utilities experienced a mix of under/over-recoveries for their gas costs in FYE19. In the following sections, the Department discusses these under/over-recoveries and the corresponding AAA true up calculations. In addition, the Department highlights certain AAA compliance reporting as applicable to the different utilities.

A. GREATER MINNESOTA GAS, INC.

1. Recovery of Gas Costs and True Up Calculations

On August 30, 2019, GMG submitted its 2019 Annual True Up Report in G022/AA-19-555 in compliance with Minnesota Rule 7825.2810. The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For FYE19, GMG reported that it over-recovered its total gas costs by $53,312, or approximately 0.88 percent, for a cumulative over-recovery of 1.30 percent.[34] By customer class, Greater Minnesota reported over/under-recoveries for the current reporting period as follows:

Table G8: Greater Minnesota Gas FYE19 Percent Over/(Under)-Recovery by Customer Class[35]
(As filed by Greater Minnesota)

Firm	1.92
Agricultural - Interruptible	(3.87)
General – Interruptible	(7.37)
Total System	0.88

Using the sales volumes forecasted by Greater Minnesota for the FYE20[36] period results in the following true up factors by customer class:

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

Firm	($0.0926)
Agricultural - Interruptible	$0.0582
General - Interruptible	$0.2273

[34] The figure of 1.30 percent represents the cumulative over-recovery of $78,407, which is the basis for GMG's FYE20 true up adjustment. For a detailed breakdown of the true up calculations, please see Greater Minnesota's True Up Report, Docket No. G022/AA-19-555.
[35] A supporting spreadsheet with detailed calculations is contained in Department Attachment G5.
[36] GMG's True Up Report, Attachment A.

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 and commodity cost factors, about which GMG stated in its AAA Report: "[t]o the extent estimated volumes and prices vary from actual purchases, a monthly over- or under-recovery will occur."[37]

- **Demand Costs** – GMG over-recovered its current demand costs by $101,151, or approximately 10.80 percent. The demand cost over-recovery includes capacity-release revenue of $40,892. Without this revenue, there was an over-recovery of demand costs of $60,259, or approximately 6.44 percent.

  Weather across the state of Minnesota in FYE19 was colder than normal, with the St. Cloud and Minneapolis/St. Paul areas experiencing weather that was 8.49 and 5.86 percent colder than normal, respectively. Based on this information, the Department concludes that GMG's demand cost over-recovery appears reasonable.

- **Commodity Costs** – GMG under-recovered its FYE19 commodity costs by $47,839, or approximately 0.94 percent. The Department concludes that GMG's under-recovery of commodity costs appears to be reasonable.

2. *Compliance and Supplemental Reporting Requirements*

Docket No. G022/M-11-804: The Commission's December 22, 2011 *Order Authorizing New Retail Service* in Docket No. G022/M-11-804 required GMG to provide in its AAA report, for each relevant 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
- 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 in the following quote included in Commission Staff in briefing papers:

[37] GMG's AAA Report, page 4.

> 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 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.[38]

On pages 4 – 5 of its AAA Report, GMG provided the discussion required by the Commission's December 22, 2011 *Order* in Docket No. G022/M-11-804, and the Department concludes that GMG complied with the reporting requirements as ordered.

Docket Nos. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-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 No. G999/AA-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 explained that it did not have any non-compliant interruptible customers that engaged in unauthorized gas use during a curtailment period. The Department concludes that GMG complied with the reporting requirements in Docket No. G999/AA-17-493.

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[38] Pages 4 -5 of the December 7, 2011 Staff Briefing Papers in Docket No. G022/M-11-804.

3. Summary and Recommendations

The Department concludes that GMG's AAA filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department recommends that the Commission:

- Accept GMG's FYE19 true up, Docket No. G001/AA-19-555.
- Allow GMG to implement its true up, as shown in Department Attachment G5.

B. GREAT PLAINS NATURAL GAS COMPANY

1. Recovery of Gas Costs and True Up Calculations

On August 29, 2019, Great Plains submitted its 2019 Annual True Up Report in Docket No. G004/AA-19-542 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 FYE19 reporting period, Great Plains over-recovered its total gas costs by $631,535, or approximately 3.49 percent, for a cumulative under-recovery of total gas costs of approximately 4.13 percent.[39] Great Plains' over-recovery by customer class for the current reporting period is shown in the following table.[40]

[39] The figure of 4.13 percent represents the cumulative over-recovery of $746,613, which is the basis for the FYE20 true up adjustment. For a detailed breakdown of the true up calculations, please see Great Plains' True Up Report, Docket No. G004/AA-19-542.

[40] 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.

Table G9: Great Plains FYE19 Percent Over-Recovery/(Under)-Recovery by Customer Class[41]
(As filed by Great Plains)

Firm	3.51
Interruptible	3.42
Total System	3.49

Using the sales volumes forecasted by Great Plains for FYE20 results in the following true up factors by district and by customer class:

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

Class	Consolidated System
Firm	$(0.2344)
Interruptible	$(0.1015)

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

- **Demand Costs** – Great Plains over-recovered its demand costs by $369,867, or approximately 10.27 percent, during the reporting period. The demand-cost over-recovery includes capacity release revenue of $8,133. Great Plains stated that the over-recovery of demand costs was due to the following: [42]

  > 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. Weather was 15.58 percent colder than normal for the twelve months ending June 30, 2019.

  The nearest weather station to Great Plains' northern service area, Fargo, ND, was 11.45 percent colder for the year and 1.20 percent colder during the November-March heating season. The nearest weather station to Great Plains' southern service area, Sioux Falls, SD, was 2.87 percent colder over the year and 3.78 percent colder during the heating season. Significant departure from normal temperatures will skew recovery of demand costs. Based on this information, the Department concludes that Great Plains' current over-recovery of demand costs appears to be reasonable.

[41] A supporting spreadsheet with detailed calculations is contained in Department Attachment G6.
[42] Great Plains' AAA Report, page 4.

- **Commodity Costs** – Great Plains over-recovered its commodity costs (including penalty revenue of $72,275[43]) by $261,668, or approximately 1.81 percent. Great Plains stated that the over-recovery was partly a result of timing differences between the cost of gas recovered in the rates and the actual gas costs.[44]

  The Department concludes that Great Plains' over-recovery of commodity costs appears to be reasonable.

2. *Compliance and Supplemental Reporting Requirements*

Docket No. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-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 No. G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

Great Plains reported in Exhibit E of its AAA Report and in response to Department IR 8 that it did not have any non-compliant gas usage in FYE19 and that no changes occurred in how it handles curtailment penalty revenue. The Department concludes that Great Plains complied with the reporting requirements in Docket No. G999/AA-17-493.

3. *Summary and Recommendations*

The Department concludes that Great Plains' AAA filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department recommends that the Commission:

- Accept Great Plains' FYE19 true up, Docket No. G004/AA-19-542.
- Allow Great Plains to implement its true up, shown in Department Attachment G6.

C. *MINNESOTA ENERGY RESOURCES CORPORATION*

In its December 8, 2014 *Order Approving Sale Subject to Conditions* in Docket No. G001,G011/PA-14-107, the Commission approved MERC's acquisition of Interstate Power & Light's gas utility serving Minnesota. 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,

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[43] Great Plains' response to Department IR 9 ($10,408 + $61,867). Responses are available upon request.
[44] Great Plains' AAA Report, page 4.

2017, following the implementation of final rates. In the relevant *Order*, the Administrative Law Judge (ALJ) in that case found MERC's proposed timeline to be reasonable.[45] In its October 31, 2016 *Findings of Fact, Conclusions, and Order,* the Commission approved the ALJ's findings.[46] FYE19 is the second 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 30, 2019, MERC-NNG submitted its FYE19 True-Up Report in Docket No. G011/AA-19-517 in compliance with Minnesota Rule 7825.2810. The Department concludes that MERC-NNG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. For the FYE19 reporting period, MERC-NNG over-recovered its total gas costs by $9,024,543, or approximately 6.66 percent, for a cumulative over-recovery of total gas costs of approximately 7.02 percent.[47]

On August 30, 2019, MERC-CON submitted its FYE19 True Up Report in Docket No. G011/AA-19-518 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 over-recovered total gas costs by $1,217,704, or approximately 5.05 percent, for a cumulative over-recovery of 5.38 percent.[48]

MERC's reported over/under-recoveries during the current period as follows:

[45] *Findings of Fact, Conclusions of Law, and Recommendation*, issued August 19, 2016, Findings 752-758, pages 143-144.
[46] *Findings of Fact, Conclusions, and Order*, issued October 31, 2016, Ordering Paragraph 2, page 54.
[47] The figure of 7.02 percent represents the cumulative over-recovery of $9,505,236, which is the basis for the FYE20 true up adjustment. For a detailed breakdown of the true up calculations, please see MERC-NNG's True Up Report, Docket No. G011/AA-19-517.
[48] The figure of 5.38 percent represents the cumulative over-recovery of $1,294,883, which is the basis for the FYE20 true up adjustment. For a detailed breakdown of the true up calculations, please see MERC-CON's True Up Report, Docket No. G011/AA-19-518.

Table G10: MERC FYE19 Percent Over-Recovery/(Under)-Recovery by System and Class[49]
(As filed by MERC)

Class[50]	NNG	CON
GS	7.76	5.69
SVJ/LVJ/SLVJ Demand	0.00	0.00
SVI/SVJ/LVI/LVJ/SLVI Commodity	(5.55)	(1.28)
Total System	6.66	5.05

Using the sales volumes forecasted by MERC for FYE20 results in the following true up factors by system and class:

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

Class	NNG	CON
GS	$(0.4127)	$(0.2915)
SVJ/LVJ/SLVJ Demand	$0.0000	$0.0000
SVI/SVJ/LVI/LVJ/SLVI Commodity	$0.2224	$0.1135

a. MERC-NNG

On August 30, 2019, concurrent with its AAA Report, MERC-NNG filed an analysis of its over/under-recoveries. MERC-NNG's over/under-recovery was due to the following demand and commodity cost factors:

- **Demand Costs** – MERC over-recovered its demand costs for the MERC-NNG system by $9,935,378, or approximately 48.44 percent. The demand cost over-recovery also includes NNG capacity-release revenue of $1,550,686.[51] Without this revenue, there was an over-recovery of demand costs of $8,384,692, or approximately 40.87 percent. On page 2 of its AAA Report, MERC-NNG explained that the over-collection of demand costs was predominantly caused by actual sales being greater than projected sales.

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[49] Supporting spreadsheets with detailed calculations are contained in Department Attachments G8 and G9.
[50] 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)
- Super Large Volume Joint (SLVJ)

[51] MERC-NNG's AAA Report, Schedule D3. Note that MERC-NNG reported $190,486 in curtailment penalty revenue (Schedule C&D of MERC-NNG's AAA Report).

As weather across the state during FYE19 was between about 0.04 and 11.45 percent colder than normal, it is logical that MERC's actual sales volumes were higher than forecasted. Based on our review of MERC's analysis of its over/under-recoveries, the Department concludes that MERC-NNG's over-recovery of demand costs appears reasonable.

- **Commodity Costs** – MERC-NNG under-recovered commodity costs by $910,835, or approximately 0.79 percent. The commodity cost under-recovery also includes DDVC revenue of $33,283. On page 3 of its NNG AAA Report, MERC explained the under collection was predominantly caused by higher than forecasted gas costs.

  Considering the price spikes experienced in November and December 2018, it is plausible that MERC would have experienced some under-recovery of its commodity costs. However, according to the monthly over/under-recovery analysis spreadsheet provided by MERC, its slight under-recovery of commodity costs was not concentrated in November or December, but instead distributed across several other months on either side of the heating season.

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

Through our review, the Department noted differences between the Daily Delivery Variance Charges (DDVCs) and other penalty charge amounts included in MERC-NNG's AAA Report and its October 16, 2019 response the Department IR 7. In MERC-NNG's AAA Report, page 5 of Schedule D.3, MERC included $33,283 of DDVCs in its FYE19 over/under cost recovery calculation for the NNG system; this $33,283 DDVC figure is also included in MERC's response to Department IR 7 as a "positive" DDVC amount. However, in addition to the $33,283 of positive DDVCs, MERC's response to IR 7 shows that the NNG system incurred a punitive DDVC amount of $44,112.30 and other penalty charges of ($175,203.85), resulting in a net total of ($97,808.59) for FYE19. The Department request that MERC explain in Reply Comments (1) whether and why the $33,283 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE19 over/under cost recovery calculation for the NNG system and (2) whether and why a difference exists between the DDVC/penalty charge amounts shown in MERC-NNG's FYE19 AAA Report and its reply to Department IR 7.

b. MERC-Consolidated

On August 30, 2019, concurrent with its 2019 AAA Report, MERC-CON filed an analysis of its over- and under-recoveries. MERC's over-recovery was due to the following demand and commodity cost factors:

- **Demand Costs** – MERC over-recovered its demand costs for the MERC-CON system by $1,399,798, or approximately 43.42 percent. The demand-cost over-recovery includes capacity-release revenue of $301,792.[52] Without the capacity release revenue, there was an over-recovery of demand costs of $1,098,006, or approximately 34.06 percent. On page 3 of its AAA Report, MERC explained that its over-collection of demand costs was caused by capacity release revenues and actual sales being higher than projected sales. The colder-than-normal weather in Minnesota during FYE19 likely contributed to MERC having, volumetrically speaking, considerably more sales than forecasted.

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

- **Commodity Costs** – MERC-CON under-recovered commodity costs by $182,094, or approximately 0.87 percent. The commodity-cost under-recovery includes balancing penalty revenue of $0.[53] On page 3 of its AAA Report, MERC-CON explained that the under collection was primarily caused by higher gas costs.

  Based on our review of MERC's analysis of its monthly over/under-recoveries and the relatively small amount of the overall under-recovery, 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:[54] In the preceding list of dockets, the Commission allowed MERC to recover through the PGA the costs associated with using financial instruments to secure natural gas supplies. The *Orders* in these dockets require MERC to report and provide in future 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 instruments entered into
- Total contracted volumes, for each instrument
- 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,

[52] MERC- CON's AAA Report, Schedule I. Note that MERC-CON reported $2,429 in curtailment penalty revenue (Schedule C&D of MERC-CON's AAA Report).
[53] MERC- CON's AAA Report, Schedule B and E, page 1.
[54] 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.

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 after-the-fact 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 NNG and CON AAA Reports, Schedules L and O, and in an Excel spreadsheet filed concurrently with its AAA Reports. The Department discusses MERC's hedging costs further in Section III of this FYE19 AAA 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/quantified description of the risk (*i.e.,* catastrophic or other type of event) that the companies are insuring against by implementing the hedging strategies and a clearly defined/quantified estimate of probability of these 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
    - 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

- 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 bill

MERC included these reporting requirements in Schedule P of its NNG and CON AAA Reports.

Docket Nos. G999/AA-14-580 and G999/AA-17-493: 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 G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

On pages 8-9 of MERC-NNG's AAA Report, MERC stated that there were nine curtailments called and five days on which unauthorized gas use occurred during FYE19, up from three in FYE18. MERC reported 38,097.1 therms of unauthorized gas use in total for the NNG system for FYE19, notably higher than the 268.26 therms of unauthorized gas use reported for FYE18. MERC-NNG's AAA Report included the required information for customers with unauthorized gas use and indicated that MERC communicated with each customer to ensure the curtailment process was understood.[55] On page 5 of MERC-CON's AAA Report, MERC reported calling two curtailments and having one day on which unauthorized gas use occurred during FYE19, up from zero in FYE18 (MERC-CON did not call any curtailments on its system in FYE18). MERC reported 485.8 therms of unauthorized gas use in total for the CON system for FYE19. MERC-CON's AAA Report included the required information for customers with unauthorized gas use and indicated that MERC communicated with each customer to ensure the curtailment process was understood.

The Department concludes that MERC complied with the reporting requirements in Docket No. G999/AA-17-493 on unauthorized gas use.

Docket Nos. G011/M-15-895 and G011/M-18-526: The Commission's May 8, 2018 *Order* in Docket No. G011/M-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. MERC-NNG provided this reporting requirement in Schedule I of its AAA Report. Additionally, 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 were available on November 1, 2018, resulting in MERC-NNG moving from a negative reserve margin to a positive reserve margin of 1.25 percent. As that reserve margin was still well below the target of 5-7 percent reserve, MERC did not release any of the capacity. The second, larger tranche is anticipated to be available starting November 1, 2019.

The Department concludes that MERC complied with the reporting requirements in Docket Nos. G011/M-15-895 and G011/M-18-526 regarding the Rochester-specific capacity release.

[55] 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 FYE19 AAA filings are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department requests that MERC explain in Reply Comments (1) whether and why the $33,283 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE19 over/under cost recovery calculation for the NNG system and (2) whether and why a difference exists between the DDVC/penalty charge amounts shown in MERC-NNG's FYE19 AAA Report and its reply to Department IR 7.

The Department recommends that the Commission:

- Accept MERC-NNG's FYE19 true up, Docket No. G011/AA-19-517, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.
- Allow MERC-NNG to implement its true up, shown in Department Attachment G8, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.
- Accept MERC-CON's FYE19 true up, Docket No. G011/AA-19-518.
- Allow MERC-CON to implement its true up, shown in Department Attachment G9.

D. *CENTERPOINT*

1. *Recovery of Gas Costs and True Up Calculations*

On September 3, 2019, CenterPoint filed its FYE19 True Up Report in Docket No. G008/AA-19-556 in compliance with Minnesota Rule 7825.2810. The Department concludes that CenterPoint's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

CenterPoint under-recovered gas costs by $8,613,194, or approximately 1.46 percent, with a cumulative under-recovery of approximately 0.33 percent[56] of its actual gas cost incurred. Excluding the $2,070,946 in revenue credits returned to customers through the FYE19 true up, CenterPoint under-recovered gas costs by $6,542,248, or 1.11 percent. By customer class, CenterPoint reported under-recoveries for the current reporting period as follows:

[56] The figure of 0.33 percent represents the cumulative under-recovery of $1,920,425, which is the basis for the FYE20 true up factors. For a detailed breakdown of the true up calculation, please see CenterPoint's True Up Report, Docket No. G008/AA-19-556.

Table G11: CenterPoint FYE19 Percent Over-Recovery/(Under)-Recovery by Customer Class[57]
(As filed by CenterPoint)

Class	
Small Volume Firm	(1.11)
Large General Service	(1.49)
Small Volume Dual Fuel	(0.40)
Large Volume Dual Fuel	(2.06)
Total System	(1.11)

Using the rate-case sales volumes forecasted by CenterPoint results in the following proposed true up factors by class.[58]

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

Class	Factor
Small Volume Firm	$0.0134
Large General Service	$(0.0249)
Small Volume Dual Fuel	$0.0056
Large Volume Dual Fuel	$0.0644

The Department's analysis of CenterPoint's true up calculation indicates that the current year's deviation between gas cost recovered and incurred was primarily caused by the following factors:

- **Demand Costs** – CenterPoint under-recovered its demand costs, including propane costs,[59] by $3,937,031, or approximately 4.14 percent. The demand cost under-recovery includes off-system sales revenue of $0 and curtailment revenue of $972,724.[60] On page 21 of its AAA Report, CenterPoint explained that it under-recovered demand costs despite weather that was about 10.8 percent colder than normal. CenterPoint further explained that, with the demand rate being an annualized value, changes in demand costs during FYE19 resulted in timing differences between costs incurred and recovered. CenterPoint also noted that its "demand smoothing" factor brought the demand cost recovery closer to the demand costs incurred.

  Weather at the Minneapolis/St. Paul weather station, where the majority of CenterPoint's load is concentrated, was 5.86 percent colder than normal for the year and 5.53 percent colder during the heating season. These temperatures would typically predict an over-recovery of demand costs, however, CenterPoint's demand smoothing

[57] A supporting spreadsheet with detailed calculations is contained in Department Attachment G10.
[58] See CenterPoint's True Up Report, page 10, for the sales volumes.
[59] Propane costs of $1,234,131 are included in demand costs. See CenterPoint's True Up Report, page 3.
[60] CenterPoint's True Up Report, page 9.

factor brought recovery closer to actual costs incurred and changed what would have been an over-recovery to an under-recovery. The Department discusses this demand smoothing factor in more detail in the *Compliance and Supplemental Reporting Requirements* subsection that follows.

The Department concludes that CenterPoint's under-recovery of demand costs appears reasonable.

- **Commodity Costs** – CenterPoint under-recovered commodity costs by $4,676,163, or approximately 0.95 percent. The commodity cost under-recovery includes off-system sales revenue of $360,133, damage revenue of $24,033, and balancing revenue of $714,054.[61] Regarding the under-recovery, CenterPoint Energy stated that "[c]ommodity-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."[62]

  CenterPoint also provided further commodity price discussion on pages 9 - 10 of its AAA Report; on page 9, in reference to the FYE19 winter, CenterPoint stated:

  > First-of-Month Market price volatility was the second highest over recent winters, averaging 64%. Over time, hedged purchases and storage gas have had a major effect on stabilizing gas supply costs billed to customers…over time, CenterPoint Energy's gas supply rate is more stable than the index, particularly for the winter period when most hedge products have been in effect.

  Considering the discussion provided by CenterPoint and the relatively minor amount of under-recovery, the Department concludes that CenterPoint's under-recovery of commodity costs appears to be reasonable.

2. Compliance and 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, G008/M-16-228, and G008/M-19-342 (Demand Adjustment Program): In Docket No. G008/M-00-980, CenterPoint 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 to provide, in its AAA reports, a summary of what the total annual

[61] *Id*.
[62] CenterPoint's AAA Report, page 21.

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. In the dockets listed at the beginning of this subsection, the Commission approved extensions of the Program. In its December 11, 2013 *Order* in Docket No. G008/M-13-728, the Commission approved CenterPoint's request "to remove the one-month lag in sales from its calculation" of the monthly demand adjustment and ordered that CenterPoint continue to comply with the reporting requirements from the previous related dockets. The Commission most recently extended the Program approvals in Docket No. G008/M-19-342, with no substantive changes from the December 11, 2013 *Order* in Docket No. G008/M-13-728. In Exhibits 3 and 4 of its AAA Report, CenterPoint included the required information. Since the inception of the Program, the estimated demand-cost recovery results have been as follows:

Table G12: CenterPoint's Demand Adjustment Program Recovery Results[63]

Year	*Over/(Under) Recovery[64] With Program[65]*		*Over/(Under) Recovery Without Program*	
	Dollars	*Percentage*	*Dollars*	*Percentage*
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[66]	$688,175[67]	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
FYE19	($6,957,804)	(7.3)	$11,757,769	12.4

[63] Table data retrieved from CenterPoint's AAA Report Exhibits 3 and 4. Note that Exhibits 3 and 4 use forecasted/estimated data to illustrate the differences in over/under-recovery of demand costs, and, therefore, the over/under-recovery figures in these exhibits do not tie to the actual annual amount the CenterPoint over/under-recovers and reports in its True Up Report.
[64] For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar-month data rather than billing-month data).
[65] Program recovery did not include the lag adjustment until FYE14.
[66] Beginning in FYE14, the Commission approved CenterPoint's request to adjust the Program for a one-month lag in sales.
[67] This figure was corrected. As of FYE14, the Program recovery includes the lag adjustment.

As highlighted in the table above, except for FYE07, FYE08, FYE13, FYE16, and FYE17, the Program appears to provide a better match of costs and recoveries within the true up year than would have been the case without the Program.[68] In FYE19, the estimated under-recovery of $6,957,804 with the Program deviates less from actual demand costs than the estimated over-recovery of $11,757,769 without the Program. The Department refers to Docket No. G008/M-19-342 for the analysis supporting the Commission's decision to grant the most recent variance to allow the demand smoothing adjustment to continue.

Table G12a shows CenterPoint's estimated over/(under) recovery with and without a 1-month lag adjustment.

Table G12a: CenterPoint's Demand Adjustment Program One-Month Lag Adjustment Results[69]

Year	*Over/ (Under) Recovery with Lag Adjustment*	*Over/ (Under) Recovery without Lag Adjustment*
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[70]	$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
FYE19	($5,227,433)	($6,957,804)

In FYE19, the estimated under-recovery of $5,227,433, assuming a one-month lag adjustment methodology, reflects a better result than the actual methodology without the lag adjustment, which shows an under-recovery of $6,957,804. The Department concludes that CenterPoint complied with the filing requirements in Docket No. G008/M-19-342.

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, the Commission granted a variance to

[68] 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) because CenterPoint'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.
[69] Table data retrieved from CenterPoint's AAA Report Exhibits 3 and 4.
[70] Beginning in FYE14, the Commission approved CenterPoint's request to adjust the Program to remove the one-month lag. The Commission required CenterPoint to continue to report "the Company's monthly demand adjustment compared to a hypothetical demand-cost recovery rate that reflects a one-month lag."

allow CenterPoint 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 this variance in Docket Nos. G008/M-08-777, G008/M-12-166, and G008/M-15-912, with the most recent extension running through June 30, 2020. In its November 3, 2004 *Order* in Docket No. G008/M-01-540, the Commission required CenterPoint to:

- Include information on the call option 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.
- 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.[71]

In its March 6, 2009 *Order* in Docket No. G008/M-08-777 (and in Docket No. G008/M-15-912), the Commission stipulated the following reporting requirements:

- Data on the specifics of any price hedging contracts, including a list of each hedging instrument entered into
- Totals contracted for each instrument
- Net gains or losses, including all transaction costs

In Exhibit 6 of its AAA Report, CenterPoint included information on its swing contracts only, as it did not purchase financial call options. CenterPoint's AAA Report 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.[72]

The Department concludes that CenterPoint complied with the filing requirements in Docket Nos. G008/M-01-540, G008/M-08-777, and G008/M-15-912. The Department discusses CenterPoint's hedging costs further in Section III of the instant FYE19 AAA Report.

Docket No. G999/AA-08-1011: The Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal year 2010. Pages 22-23 as well as in Exhibits 6, 7, and 8 of CenterPoint's AAA Report provide this information. The Department concludes that CenterPoint complied with the filing requirements in Docket No. G999/AA-08-1011.

Docket No. G008/GR-08-1075 (Off-System Sales): In Docket No. G008/GR-08-1075, the Commission ordered CenterPoint 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

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[71] In Docket No. G999/AA-16-524, CenterPoint explained that during the winter, its swing gas is valued the same as "spot market" gas, so there is no comparison to provide. CenterPoint requested to discontinue this compliance item until such time that the difference is not zero, and the Commission approved this request.
[72] Additional discussion provided on pages 22-23 of CenterPoint's AAA Report.

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 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) of the same *Order* required that CenterPoint split the off-system sales 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 included the required information on pages 9 and 13 of its True Up Report.

The Department concludes that CenterPoint calculated its incentive on off-system sales[73] and allocations among classes correctly, and that CenterPoint complied with the filing requirements in Docket No. G008/GR-08-1075.

Docket Nos. G999/AA-14-580 and G999/AA-17-493: The Commission's August 24, 2015 *Order* in Docket No. G999/AA-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 G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20. On page 18 and in Exhibit 12 of its AAA Report, CenterPoint indicated that it had 658,815 therms of unauthorized gas use in FYE19, a substantial increase from having no unauthorized gas use in FYE18. CenterPoint explained that it credited $1,246,768 to firm customers to account for the financial penalties assessed to interruptible customers that had unauthorized gas use. CenterPoint also stated the following on page 18 of its AAA Report:

> Equipment failure was the most frequently cited reason for customers' inability to discontinue gas use. In those cases, customers made repair calls and maintenance requests to rectify the situations…About a fourth of those who used unauthorized gas had staffing issues where staff either did not know they had to curtail or staff was not trained in using the backup system. Follow-up included emphasizing the one-hour response window, customers tracing equipment, and changing rate classes. The Company learned that about 11% of those contacted no longer had working backup systems and were unable to curtail. In those cases, follow-up is required to see how CNP may be able to meet the customers' changed service needs.

[73] In Docket No. G008/GR-08-1075, the Commission allowed CenterPoint to earn an incentive equal to the approved overall rate of return on its off-system sales. On page 13 of its True Up Report, CenterPoint's incentive totaled $8,966 ($369,099- $360,133).

The Department concludes that CenterPoint complied with the reporting requirements in Docket No. G999/AA-17-493.

3. Summary and Recommendations

The Department concludes that CenterPoint's FYE19 AAA Report is complete with respect to the filing requirements in Minnesota Rules 7825.2390 through 7825.2920. Based on our review, the Department recommends that the Commission:

- Accept CenterPoint's FYE19 true up, Docket No. G008/AA-19-556.
- Allow CenterPoint to implement its true up, shown in Department Attachment G10.

E. XCEL GAS

1. Recovery of Gas Costs and True Up Calculations

On August 30, 2019, Xcel Gas submitted its FYE19 True Up Report in Docket No. G002/AA-19-551 in compliance with Minnesota Rule 7825.2810. Based on our 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 $4,289,347, or approximately 1.34 percent, during the reporting period, with a cumulative under-recovery of approximately 1.32 percent.[74] By customer class, Xcel Gas reported under/over-recoveries for the current reporting period as follows:

Table G13: Xcel Gas FYE19 Percent Over-Recovery/(Under)-Recovery by Customer Class[75]
(As filed by Xcel Gas)

Class	
Residential	(0.22)
Commercial/Industrial (C/I)	(1.12)
Demand Billed	2.41
Demand Billed Commodity	(5.22)
Small Interruptible (SVI)	(3.51)
Medium & Large Interruptible (M&LVI)	(6.70)
Total	(1.34)

[74] The figure of 1.32 percent represents the cumulative under-recovery of $4,232,160, which is the basis for the FYE20 true up adjustments. For a detailed breakdown of the true up calculations, see Xcel Gas' True Up Report, Docket No. G002/AA-19-551.
[75] Supporting spreadsheets with detailed calculations are contained in Department Attachment G11.

Using the sales volumes forecasted by Xcel Gas for FYE20[76] results in the following true up factors by class, as calculated by Xcel Gas in its filing:

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

Class	
Residential	$0.01220
C/I	$0.04630
Demand Billed Demand	($0.14940)
Demand Billed Commodity	$0.16400
SVI	$0.12590
M&LVI	$0.24120

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

- **Demand Costs, Including Demand Billed Costs:** Xcel Gas over-recovered Minnesota demand costs by $3,098,460, or 6.38 percent. The demand cost over-recovery also includes interruptible curtailment penalty revenue of $773,696 and capacity release revenue of $366,117.[77] Without these revenues, there was an over-recovery of demand costs of $1,958,647, or 4.03 percent. According to Xcel, actual FYE19 sales were approximately 9.56 percent higher than forecasted sales in the monthly PGA, resulting in the over-recovery of demand costs.[78]

  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 and, during the FYE19 heating season, it credited $3,772,919 of demand costs to customers. However, Xcel made a portion of this $3,772,919 credit in error. Upon discovering a miscalculation in its Monthly Demand True Up Mechanism, Xcel disclosed this credit error in its September PGA (filed August 29, 2019) and in the instant annual filing. Xcel stated:

  > The impact of this error was that the Company credited back to customers an additional $876,013 in demand cost over-recovery through this mechanism than would have otherwise been. ($3,772,919 of demand over-recovery was credited back to customers through the mechanism instead of $2,896,906.) For purposes of the Monthly Demand True-up mechanism, we inadvertently used Minnesota

[76] Xcel Gas' True Up Report, Schedule B, page 2.
[77] Xcel Gas' responses to Department IRs 8 and 6. The capacity release revenue of $336,117 includes internal and external capacity release revenues.
[78] Xcel's AAA Report, Attachment B, Schedule 3, page 3.

> Company sales (including both MN and ND sales) instead of Minnesota state sales to allocate the PGA year sales to month. In other words, the "calculated sales" were incorrect, with more sales allocated to commercial and less to residential than should have been. This error produced incorrect sales differences and corresponding monthly demand true-up rates for credit or recovery. The Monthly Demand True-up rate caps were not affected by this error. No other monthly PGA calculations were affected by this error.
>
> The Company does not intend to rebill customers at this time. Essentially the error accelerated a credit of $876,013, which was expected in the 2019-20 PGA true-up, to the 2018-19 year. The alternative-rebilling customers to remove the credit at this time only to provide the credit over the next twelve months could lead to customer confusion and serves no practical purpose.[79]

Xcel Gas stated that without the mechanism, its over-recovery of demand costs would have been approximately 14.14 percent.[80]

At the Minneapolis/St. Paul weather station, where the majority of Xcel's load is concentrated, annual temperatures were 5.86 percent colder than normal and 5.53 percent colder during the heating season. Considering the colder-than-normal weather, the disclosed error, and the revenue credits from curtailment penalties and capacity release, the Department concludes that Xcel Gas' demand cost over-recovery appears reasonable.

- **Commodity Costs, Including Peak Shaving Costs:** During FYE19 Xcel Gas under-recovered commodity costs by $7,387,808, or 2.72 percent. The commodity cost under-recovery also includes balancing penalty revenue of $119,495.[81] Without this revenue, there was an under-recovery of commodity costs of $7,507,303 or approximately 2.77 percent. Xcel Gas stated that the under-recovery was due to:

> …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 1.0 cents per therm. Because customer consumption varies by class

[79] Xcel's AAA Report, pages 1-2 of the introduction letter.
[80] Xcel's AAA Report, Attachment B, Sch. 3, page 3 and True Up Report, Schedule I.
[81] Xcel Gas' True Up Report, Schedule D, page 1 and Xcel Gas' response to Department IR 9 under Daily Imbalance Penalty Revenue.

> from month to month and price deviation varies from month to month, individual classes had varying results. [82]

Based the discussion provided by Xcel, Department concludes that Xcel's under-recovery of commodity costs appears to be reasonable.

2. Compliance and Supplemental Reporting Requirements

Docket No. G002/M-94-103: The Commission required Xcel to return all past, present, and future capacity release revenue from all sources to firm customers using FERC Account 805.1. In Schedule H of Xcel's True Up Report, Xcel complied with the Commission's *Order* by returning capacity release revenue from all sources to firm customers.

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 extending rule variance to allow Xcel Gas to recover its 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
- Total volumes contracted for, for each instrument
- Net gain or loss, including all transaction costs for each instrument in comparison to the appropriate monthly and daily spot index prices
- Schedule of hedging costs

[82] Xcel Gas' AAA Report, Attachment B, Schedule 3, pages 3-4.

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.

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 and granted a variance to Minnesota Rule 7825.2700, subpart 5 for Xcel Gas. Xcel implemented the Monthly Demand Cost True Up Mechanism in October 2004. In the above-listed dockets, the Commission approved extensions of the program through September 30, 2020.

The Monthly Demand Cost True Up Mechanism should result in billing rates that are:

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

The Demand Cost True Up Mechanism is adjusted by capacity release as approved in Docket No. G002/M-11-203. This mechanism 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's annual true up filings:

- Annual demand cost recovery absent the adjustments
- Total annual adjustment recovery
- Remaining current year demand cost recovery true up balance

Xcel's FYE19 True Up Report, Schedule I, includes the required information on the Demand Cost True Up Mechanism results. Since the implementation of this mechanism, the demand cost recovery results have been as follows:

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

Year	*Over/(Under)[83]Recovery with Mechanism*		*Over/(Under) Recovery without Mechanism*	
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
FYE19	$3,098,460	6.38	$6,871,379	14.14

Table G14 shows that, 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 FYE19, the actual demand cost over-recovery of $3,098,460 was substantially less than the hypothetical over-recovery of $6,871,379. 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: The Commission directed CenterPoint, MERC, and Xcel Gas to provide the Department with information about their hedging programs, beginning in fiscal year 2010. Xcel provided this required information in Attachment G, Schedules 2 through 5 in its AAA 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's 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 of, the specific accounting entries for, 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 reports. The approved Capacity Utilization Plan includes both natural gas and electric transactions.

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

During FYE19, the Capacity Utilization Plan resulted in net savings to Xcel Gas of approximately $200,588 and savings to Xcel Electric of approximately $0 from avoided storage fees.[84]

The Department concludes that Xcel Gas complied 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 No. G999/AA-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 No. G999/AA-17-493, the Commission required all regulated natural gas utilities to provide this information for an additional three annual reports, through FYE20.

Xcel Gas reported 153,898 therms of unauthorized gas use for FYE19. Xcel Gas detailed its communication procedures to avoid or address unauthorized use.[85] The Department concludes that Xcel Gas complied with the Commission's *Order* in Docket No. G999/AA-17-493.

Docket Nos. G002/M-15-149, G002/M-16-396, G002/M-17-510, G002/M-18-323 and G002/M-18-631: The Commission's October 21, 2015 *Order* and July 19, 2016 *Order* required that Xcel Gas 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 and 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. In Docket No. G002/M-18-631, Xcel Gas requested and was granted a three-year variance for collection of taxes through 2021.

Xcel Gas included the required information in its AAA Report, Attachment G, pages 12-13, stating the following:

> 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 $1,000,465 was amortized for the July 2018 to June 2019 gas year. The total amount of tax recovered from Minnesota gas ratepayers for this lump sum tax assessment during the July 2018 to June 2019 gas year is $1,102,478.
>
> The Company was assessed $689,942 in Kansas natural gas storage-related ad valorem tax costs in 2018, of which $593,001 was allocated to Minnesota…The total amount of tax collected from Minnesota gas ratepayers during the July 2018 to June 2019 gas year is $703,637.

[84] Xcel Gas' AAA Report, Attachment G, pages 10-11.
[85] Xcel's AAA Report, Attachment G, page 14 and Schedule 8.

The Department concludes that Xcel Gas complied with the Commission's *Orders* in Docket Nos. G002/M-15-149, G002/M-16-396, G002/M-17-510, G002/M-18-323 and G002/M-18-631.

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 our review, the Department recommends that the Commission:

- Accept Xcel Gas' FYE19 true up, Docket No. G002/AA-19-551.
- Allow Xcel Gas to implement its true up, shown in Department Attachment G11.

III. ADDITIONAL INFORMATION

A. AVERAGE ANNUAL RESIDENTIAL CUSTOMER BILLS

Using data supplied by the utilities in their responses to Department IR 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 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:

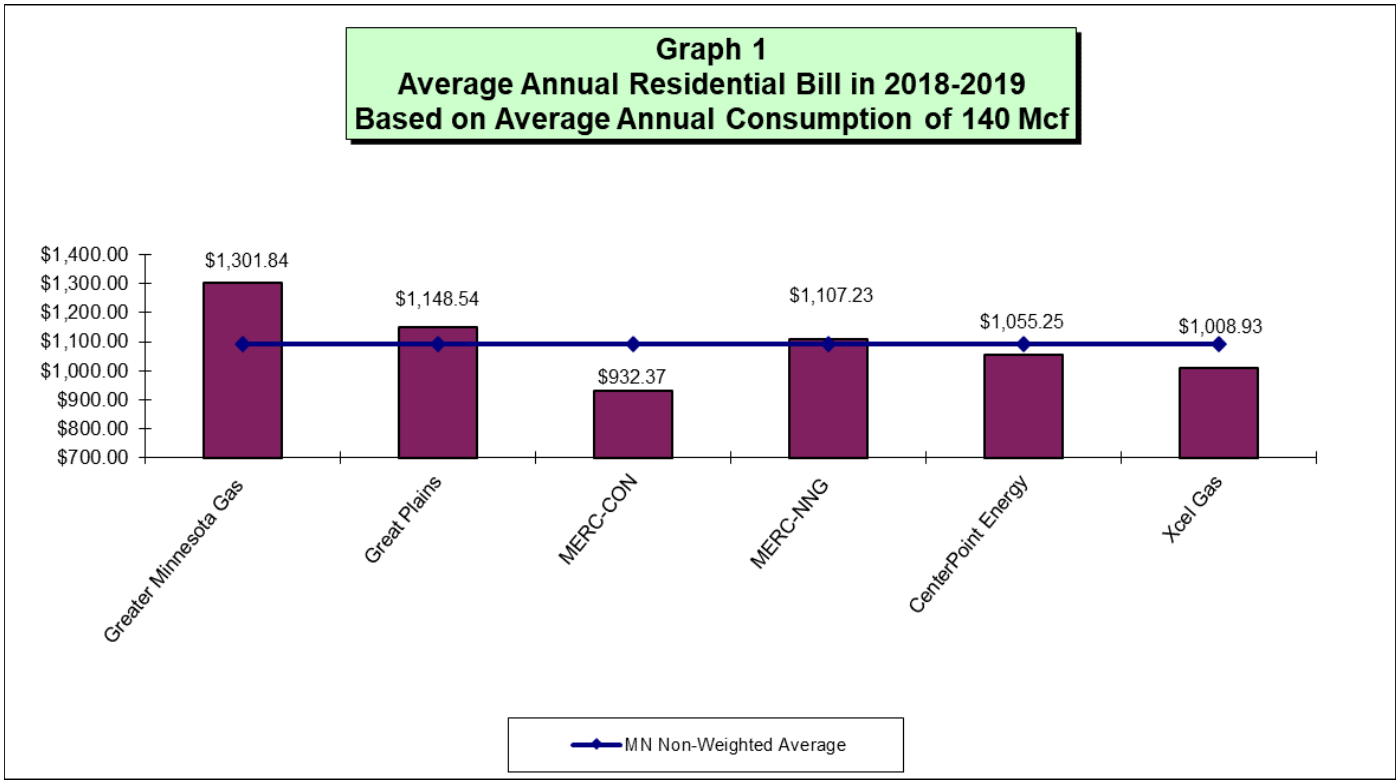
- customer charge
- per-unit energy consumption rate
- average customer consumption of 140 Mcf per year[86]

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.[87]

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

[86] 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.
[87] 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.

a miscellaneous demand-entitlement filing.[88] 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.



Graph 1 shows that, based on a consumption level of 140 Mcf, average annual residential bills[89] range from a high of $1,301.84 for customers served by GMG to a low of $932.37 for customers served by MERC-CON.

The following Table G15 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 IR 1.[90]

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88 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.

89 Amounts shown in Graph 1 are not actual averages for customers on any system, as 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.

90 Responses are available upon request.

Table G15: Average Annual Residential Bill and Average Use per Utility for the FYE19 Reporting Period

Utility	*Average Usage Rankings*[91]	*Average Use*[92] *(Mcf)*	*Annual Bill Rankings*	*Total Annual Bill*	*Average Cost per Mcf*[93]	*Annual Customer Charges*
GMG	2	93.0	6	$899.04	$9.67	$102.00
Great Plains	1	89.0	3	$762.93	$8.57	$90.00
MERC-CON	4	96.2	1	$678.59	$7.06	$121.56
MERC-NNG	3	94.9	5	$789.42	$8.32	$121.56
CenterPoint	6	98.7	4	$779.06	$7.89	$119.00
Xcel Gas	5	98.0	2	$738.65	$7.54	$108.00

As shown in Table G15, based on actual consumption, CenterPoint customers had the highest average consumption (98.7 Mcf), and GMG had the highest average annual residential bill ($899.04) during FYE19.[94]

In reference to the information provided in Graph 1, Table G15, and Department Attachment G13, the Department notes that utility costs are driven by several factors, including load, 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).

The non-gas portion of a utility's base rates are developed independently in a general rate case proceeding. 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

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[91] The rankings throughout this report are listed in the format from lowest to highest (*e.g.,* average use, cost, and rate).

[92] The average annual usage amount reported in response to Department IR 1 is not weather normalized but reflects the different heating degree days based on location.

[93] 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.

[94] 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
FYE19 CenterPoint Energy and GMG	99 Mcf	$899.04

GMG continues to have the highest average residential bills, due to its high non-gas margin. See Table G18 for more detail.

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 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[95] commodity costs incurred by the utilities and passed on to ratepayers in the monthly PGAs, as reported in the utilities' true up reports. Certain tables in this report provide the Minnesota weighted average and the Minnesota non-weighted average amounts. The Department includes the non-weighted average, because the weighted average is dominated by CenterPoint, Minnesota's largest natural gas provider.

Table G16: FYE19 Total Weighted Average Cost of Commodity PGA Recovered Versus Actual Incurred[96]

Utility	*Recovered PGA Commodity Rate $/Mcf*	*Actual Annual Commodity Rate $/Mcf*	*Percent Over/ (Under) Recovery*
GMG	$ 3.2236	$ 3.2542	(0.94%)
Great Plains	$ 3.6882	$ 3.6227	1.81%
MERC-CON	$ 3.2361	$ 3.2646	(0.87%)
MERC-NNG	$ 3.7990	$ 3.8293	(0.79%)
CenterPoint	$ 3.6297	$ 3.6644	(0.95%)
Xcel Gas	$ 3.3150	$ 3.4079	(2.72%)
Weighted MN Average	$ 3.5404	$ 3.5909	(1.41%)
Non-Weighted MN Average	$ 3.4819	$ 3.5072	(0.72%)

[95] 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).
[96] The numbers used and the detailed calculations are contained in Department Attachment G15.

Table G16 demonstrates that all the PGA systems, except Great Plains, slightly under-recovered FYE19 commodity costs, with Xcel Gas having the greatest percentage of under-recovery at 2.72 percent. Great Plains over-recovered commodity costs by just 1.81 percent.

The following Table G16a shows the difference between FYE19 and prior year Minnesota non-weighted average commodity costs; these figures are nominal costs and are not adjusted for either inflation or weather conditions. Based on the data, the actual Minnesota non-weighted average commodity cost of gas during FYE19 was $3.5072 per Mcf, which represents an approximately four percent increase compared to the FYE18 reporting period. However, Table G16a shows that the FYE19 commodity cost level is substantially lower than in many of the prior reporting periods over the last 20 years.

Table G16a: Non-Weighted Average Commodity Costs

Reporting Period	*Rate (Mcf)*	*Percentage of Increase/ (Decrease) Between Prior Year and FYE19*
FYE19	$3.5072	
FYE18	$3.3743	4%
FYE17	$3.4053	3%
FYE16	$2.9051	21%
FYE15	$4.1574	(16%)
FYE14	$5.4831	(36%)
FYE13	$3.4442	2%
FYE12	$3.5238	(0%)
FYE11	$4.3001	(18%)
FYE10	$4.7259	(26%)
FYE09	$6.1826	(43%)
FYE08	$7.4936	(53%)
FYE07	$7.6177	(54%)
FYE06	$8.8345	(60%)
FYE05	$6.3167	(44%)
FYE04	$5.3364	(34%)
FYE03	$4.7441	(26%)
FYE02	$2.6524	32%
FYE01	$6.0288	(42%)
FYE00	$2.5356	38%

The analysis in Table G16, comparing the PGA commodity costs recovered versus those actually incurred, 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 in the following Table G17. The comparison of total costs per Mcf incurred 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 for Minnesota gas utilities during FYE19.

Table G17: FYE19 Total System Gas Costs (Demand and Commodity)[97]

Utility	*PGA Recovered ($/MMBtu)*	*Rank*	*Current-Period Actual incurred Gas Cost ($/MMBtu)*	*Rank*	*Actual Over/(Under) ($/MMBtu)*	*Percentage Over/(Under) Recovery*
GMG	$3.8869	**1**	$3.8528	**2**	$0.0341	0.88%
Great Plains	$4.6831	**5**	$4.5249	**6**	$0.1581	3.49%
MERC-CON	$3.9595	**2**	$3.7690	**1**	$0.1905	5.05%
MERC-NNG	$4.8134	**6**	$4.5127	**5**	$0.3007	6.66%
CenterPoint	$4.3070	**4**	$4.3557	**4**	$(0.0486)	(1.12%)
Xcel Gas	$3.9648	**3**	$4.0187	**3**	$(0.0539)	(1.34%)
MN Weighted Avg.	$4.2547		$4.2543		$0.0004	0.01%
MN Non-Weighted Avg.	$4.2691		$4.1723		$0.0968	2.32%

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). The six PGA systems had a mix of over- and under-recovery of total gas costs during the reporting period, with MERC-NNG reporting the greatest percentage of over-recovery at 6.66 percent. Great Plains had the highest and MERC-CON had the lowest actual gas cost.

Table G17a below shows the difference between FYE19 and prior year Minnesota non-weighted average total system gas costs over each of the previous years' rates; these figures are nominal costs and are not adjusted for either inflation or weather conditions. Based on the data, the actual Minnesota non-weighted average total system cost of gas was $4.1723 per Mcf for FYE19, representing an approximately four percent increase from the FYE18 reporting period.

[97] The numbers reported in Table G17 are from the true up report 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 (Mcf)*	*Percentage of Increase/ (Decrease) Between Prior Year and FYE19*
FYE19	$4.1723	
FYE18	$4.0254	4%
FYE17	$4.1520	0%
FYE16	$3.7072	13%
FYE15	$4.9621	(16%)
FYE14	$6.2268	(33%)
FYE13	$4.3327	(4%)
FYE12	$4.7892	(13%)
FYE11	$5.3295	(22%)
FYE10	$5.7062	(27%)
FYE09	$6.9548	(40%)
FYE08	$8.3613	(50%)
FYE07	$7.8131	(47%)
FYE06	$9.7936	(57%)
FYE05	$7.2930	(43%)
FYE04	$6.2626	(33%)
FYE03	$5.5635	(25%)
FYE02	$3.4941	19%
FYE01	$6.8382	(39%)
FYE00	$3.4529	21%

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

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

Table G19: FYE19 Firm Peak-Day Demand Profiles[98]

Utility[99]	*Firm Design Day Demand (Mcf)*	*Firm Peak-Day Demand Deliverability (Mcf)*	*Annual Firm Throughput (Mcf)*	*Annual Firm Load Factor*[100]	*Reserve Margin*[101]
GMG	12,704	14,109	1,302,354	26.78%	11.06%
Great Plains	33,674	35,545	3,310,998	29.92%	5.56%
MERC-CON	57,071	57,949	4,825,697	22.99%	1.54%
MERC-NNG	275,681	311,756	24,507,563	24.97%	13.09%
CenterPoint	1,373,000	1,409,596	125,202,736	27.36%	2.67%
Xcel Gas	735,741	779,864	76,070,426	32.34%	6.00%
MN Totals	2,487,871	2,608,819	235,219,774	28.41%	4.86%[102]

Table G19 shows that Minnesota's gas utilities exhibit a firm load factor between approximately 23 and 32 percent for MERC-CON and Xcel Gas, respectively. The weighted average reserve-margin percentage, which includes each utility's contracted transportation and peak-shaving capacity, was 4.86 percent for FYE19, representing a 25.8 percent increase in the statewide reserve margin compared to the FYE18 3.86 percent average. As shown in Table G19, the reserve margins range from 1.54 percent for MERC-CON to 13.09 percent for MERC-NNG.

The Department supports the continuation of the Commission's requirement that the reserve margins be included in the AAA reports, because the information is useful for comparison purposes. However, the Department conducted no analysis of the reserve margins in the current filing, as each utility's reserve margin is analyzed by the Department and approved by the Commission the annual demand-entitlement filings.

Using data provided by the utilities in response to information requests, the Department compared each gas utility's firm peak-day demand deliverability to its actual firm peak-day use. The following Table G20 summarizes this information.

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[98] See Department Attachment G20.

[99] The utilities provided additional discussion on their reserve margins for FYE19 in the following demand entitlement filings: GMG, G022/M-18-232; Great Plains, G004/M-18-454; MERC-CON, G011/M-18-527; MERC-NNG, G011/M-18-526; CenterPoint, G008/M-18-462; Xcel Gas, G002/M-18-528.

[100] 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).

[101] 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.

[102] This percent represents the weighted average of Minnesota gas utilities' reserve margins.

Table G20: FYE19 Comparison of Firm Peak-Day Demand Usage

Utility/System	*Firm Peak Day Demand Deliverability*[103] *(Mcf)*	*Actual Firm Peak Day Usage (Mcf)*	*Actual Firm Requirement*	*Actual Peak Date*
GMG	14,109	13,323	94%	01/29/19
Great Plains	35,545	30,320	85%	01/29/19
MERC-CON	57,949	57,517	99%	01/29/19
MERC-NNG	311,756	268,848	86%	01/29/19
CenterPoint	1,409,596	1,253,519	89%	01/29/19
Xcel Gas	779,864	644,535	83%	01/30/19
MN Totals	2,608,819	2,268,062	87%	

Table G20 shows that all regulated gas utilities in Minnesota were able to meet their actual firm peak-day FYE19 usage within their proposed demand entitlement levels. The utilities had an aggregate peak-day usage, or send out, of 2,268,062 Mcf, representing 87 percent of their aggregate planned peak of 2,608,819 Mcf for FYE19. The FYE19 aggregate actual peak day usage is 16 percent higher than the 1,962,673 Mcf reported in FYE18.

D. DAILY DELIVERY VARIANCE CHARGES

In choosing a reasonable balance of pipeline services, a utility determines 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 daily service, especially during extreme weather. In general, when a utility does not nominate its daily amounts (or cannot schedule the amount of capacity needed due to portfolio limitations) within a given percentage of the actual entitlement level used, it faces pipeline penalty charges.

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 penalty charges are known as positive, negative, or punitive daily delivery variance charges (DDVCs). The current Northern DDVC cost structure for gas usage exceeding nominated levels is as follows:[104]

[103] Demand deliverability includes contracted firm transportation, on-line storage capacity, and the maximum daily injection capacity of peak-shaving facilities.
[104] See Northern Natural Gas Company’s FERC Gas Tariff, Vol. No. 1, Sheet No. 53.

Table G21: NNG's DDVC Structure[105]

Charge Type	*Current Charge*
Negative DDVC	0.40[106]
Positive DDVC	$1.00[107]
Punitive DDVC	5 x SMS Rate[108]
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

The Commission previously ordered each regulated gas utility to provide a listing of the pipeline penalties they incurred.[109] Table G22 provides a summary of the pipeline penalties incurred during the FYE19 reporting period.

[105] 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.
[106] 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.
[107] *Id.*
[108] *Id.*
[109] 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.

Table G22: FYE19 Daily Delivery Variance Charges (DDVC)[110] Incurred[111]

Utility/System	*DDVC (Mcf)*	*DDVC*	*Total Gas Costs*	*Percent of Total Gas Costs Represented by Penalties*
GMG	17,731	$3,985	$6,025,911	0.0661%
Great Plains	12,429	($5,295)	$18,070,263	(0.0293%)
MERC-CON	0	$0	$24,090,158	0.0000%
MERC-NNG	61,467	($97,809)	$135,435,723	(0.0722%)
CenterPoint	399,588	$168,467	$586,074,385	0.0287%
Xcel Gas[112]	20,133	$19,663	$319,749,687	0.0061%
MN Totals	511,348	$89,012	$1,089,446,127	0.0082%

Table G22 shows that the penalties incurred by the gas utilities range from $0 for MERC-CON to $168,467 for CenterPoint. On a percentage basis, the penalties comprise a very small portion of the utilities' gas costs. In their responses to the Department's IR 7, utilities identified the amount of each type of DDVC imposed. Table G23 provides a summary of the type of DDVC penalty incurred during the FYE19 reporting period.

Table G23:[113] FYE19 Amount of DDVCs Incurred by Type

Utility/System	*Positive & Negative*	*Punitive*	*Total*	*Percent of Total MN DDVCs*
GMG	$2,117	$1,868	$3,985	4.48%
Great Plains	($5,295)	$0	$(5,295)	(5.95%)
MERC-CON	$0	$0	$0	0.00%
MERC-NNG	($141,921)	$44,112	$(97,809)	(109.88%)
CenterPoint	$168,467	$0	$168,467	189.26%
Xcel Gas	$19,663	$0	$19,663	22.09%
MN Totals	$43,031	$45,981	$89,012	100%

Table G23 shows that all Minnesota regulated gas utilities, except MERC-CON incurred some type of DDVC during the FYE19. Total DDVC penalties for all gas utilities decreased by $6,329 (from $95,341 in FYE18 to $89,012 in FYE19), or approximately 7 percent, compared to FYE18. Only GMG and MERC-NNG incurred punitive penalties during FYE19. The NNG penalty charge credits received by each utility are shown separately in Table G25a.

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[110] Viking's charges are called overrun charges rather than DDVC's. Further, Viking does not have a punitive charge category.

[111] Table G22 summarizes the data provided in Department Attachment G14.

[112] Xcel's charges include DDVCs, as well as overrun charges on the Viking and Williston Basin Interstate Pipeline (WBI) systems.

[113] Table G23 summarizes the data provided in Department Attachment G14.

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.[114] An intraday nomination is one electronically submitted after the initial nomination. Intraday nominations may be used to nominate 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.[115] 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)
- 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, advanced nomination decisions, and limited opportunities to make intraday nominations. Moreover, a utility's ability to make appropriate intraday 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 available tools to minimize DDVC penalties, such as using pipeline storage facilities and peak-shaving plants or curtailing interruptible customers.

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

As mentioned, utilities must nominate and use interstate pipeline capacity in a responsible manner or face penalties. Therefore, utilities have established guidelines for system use for transportation and interruptible customers and apply penalties to customers who do not follow these guidelines when using the gas system.

All of Minnesota's regulated gas utilities have received Commission approval to implement 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
- encourage customers to nominate and balance gas supplies responsibly

Curtailment penalties and balancing penalties are discussed in the following sections.

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[114] See Northern Natural Gas Company's FERC Gas Tariff, Sixth Revised Vol. No. 1, Third Revised Sheet No. 257, issued February 1, 2016.
[115] *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.

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; unlike firm customers, interruptible customers do not pay for demand/capacity costs. If an interruptible customer fails to curtail when notified, the utility (not the interruptible customer) may face pipeline penalties, which, in turn, would raise rates for all customers. Theoretically, failure to curtail also could jeopardize the reliability of gas service to firm customers. Therefore, the Commission approved utility tariffs under which utilities charge curtailment penalties to interruptible customers who fail to respond to curtailment notices. Below is a summary of the revenue from curtailment penalties imposed on interruptible customers during FYE19.

Table G24: FYE19 Revenue from Curtailment Penalties[116]

Utility/System	*Total Penalties*	*Percent of Total Penalties*	*Total Gas Costs*	*Percent of Total Gas Costs Represented by Penalties*
GMG	$0	0.00%	$6,025,911	0.0000%
Great Plains	$0	0.00%	$18,070,263	0.0000%
MERC-CON	$2,429	0.13%	$24,090,158	0.0101%
MERC-NNG	$190,486	9.82%	$135,435,723	0.1406%
CenterPoint	$972,724	50.15%	$586,074,385	0.1660%
Xcel Gas	$773,969	39.90%	$319,749,687	0.2421%
MN Total	$1,939,608	100.00%	$1,089,446,127	0.1780%

Table G24 shows that three utilities charged curtailment penalties on interruptible (or dual-fuel) customers. For FYE19, the utilities charged a total of $1,939,608 in curtailment penalties, an increase of $672,194 from the FYE18 curtailment penalties of $1,267,414. This increase is attributable primarily to CenterPoint, which charged no curtailment penalties in the preceding reporting period. Penalties charged to customers in FYE19 made up a very small portion of total costs for the period. The utilities return the revenues from these curtailment penalties to firm customers as a credit to demand cost in the annual true ups.

[116] The penalties listed in Table G24 are taken from the utilities' responses to Department IR 8. Responses are available upon request.

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* addressed, among other things, the unauthorized gas use that took place during the severely cold weather associated with the polar vortex of the FYE19 heating season. CenterPoint's and Xcel's relatively high levels of unauthorized gas use were among the topics scrutinized by the investigation. The Commission's November 6, 2019 *Order* in Docket No. E,G999/CI-19-160 approved certain changes to the utilities' tariffs for interruptible customers and required compliance filings aimed at mitigating future unauthorized gas usage as well as improving the management of future extreme weather events. Because we believe that the unauthorized gas usage and the associated penalties for FYE19 have been addressed in the referenced investigation, the Department does not provide further analysis of this issue in the instant FYE19 AAA Report. However, the Department is cognizant that unauthorized gas usage may be an ongoing issue for Minnesota's natural gas systems, and we intend to continue to carefully review the relevant data in future AAA reports.

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 as cited 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 transportation customer)[117] 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 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 contains a summary of the revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers during FYE19.

[117] This is generally true, 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.

Table G25: FYE19 Revenue from Balancing Penalties[118]

Utility/System	*Balancing Penalty Rev.*	*Penalty Rev. as a Percent of Total Penalties*	*Total Gas Costs*[119]	*Penalty Rev. as a Percent of Total Gas Costs*
GMG	$6,658	0.62%	$6,025,911	0.1105%
Great Plains	$10,408	0.97%	$18,070,263	0.0576%
MERC-CON	$59,218	5.50%	$24,090,158	0.2458%
MERC-NNG	$167,344	15.54%	$135,435,723	0.1236%
CenterPoint	$714,055	66.29%	$586,074,385	0.1218%
Xcel Gas	$119,495	11.09%	$319,749,687	0.0374%
MN Total	$1,077,178	100.00%	$1,089,446,127	0.0989%

Table G25 shows the revenue from balancing penalty revenue collected from transportation customers by gas utilities ranges from $6,658 (GMG) to $714,055 (CenterPoint) for FYE19. The FYE19 total balancing penalty revenue of $1,077,178 represents a 16 percent decrease from the FYE18 amount of $1,278,071. In addition to the above revenue from balancing penalties, NNG pays an annual penalty charge credit to all shippers on its system. The utilities reported receiving the following credits for FYE19:

Table G25a: FYE19 NNG Penalty Charge Credits by Utility[120]

GMG	$2,396,104
Great Plains	$61,867
MERC	
CON	$0
NNG	($53,696)
CenterPoint	($388,600)
Xcel Gas	$158,853
MN Total	$2,174,527

F. PEAK-DAY PIPELINE TRANSPORTATION SOURCES

In its analysis of gas supply peak-day reliability, the Department considered (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). The following Table G26 shows the variety and contribution of pipelines supplying peak-day firm transportation capacity to Minnesota utilities. The

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118 The data provided in Table G25 is taken from the response to Department IR 9.

119 The figures listed in the column entitled "Total Costs Incurred" in Table G25 are taken from the gas utilities' true up reports. Total costs incurred include demand and commodity costs.

120 The data provided in Table G25a is taken from the response to Department IR 9.

peak-day capacity for FYE19 was 2,701,717 Mcf, an increase of less than one percent from the 2,683,496 Mcf reported for FYE18.

Table G26: FYE19 Summary of Utilities' Gas Supply Transportation Sources Total Minnesota Peak Quantity[121]

Pipeline	*Peak-Day Quantity (Mcf per day)*	*Peak -Day Quantity Percent of Total*
Northern Natural Gas Co.	1,876,941	69.47%
Viking Gas Transmission Co.	220,057	8.15%
Great Lakes Pipeline Co.	31,358	1.16%
Other Pipelines	47,361	1.75%
Peak Shaving & Online Storage	526,000	19.47%
MN Total	2,701,717	100.00%

The percentage of peak-day capacity provided by each of the pipelines listed in Table G26 aligns closely with the FYE18 percentages. NNG provides by far the greatest amount, 69.47 percent, of peak-day capacity to Minnesota utilities. 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 some utilities may have more options than others in choosing pipeline sources, pipeline differentiation does not appear to impact service reliability.

G. 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, 2 to 72 for firm spot supplies, and 0 to 6 for interruptible sources. Table G27 below shows the number of long-term firm, firm spot, and interruptible suppliers used by each utility during the FYE19 heating season.

Table G27: FYE19 Number of Suppliers[122]

Utility	*Firm Long-Term Suppliers*	*Firm Spot Suppliers*	*Interruptible Suppliers*
GMG	0	6	6
Great Plains	2	2	4
MERC[123]	72	72	0
CenterPoint	13	9	0
Xcel Gas	20	23	0

[121] The data provided in Table G26 is taken from the response to Department IR 4.
[122] Table G27 is based on the utilities' responses to Department IR 4.
[123] MERC provided the number of suppliers from which they can potentially purchase gas. MERC also stated that it does not purchased an interruptible gas supply.

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 proceed on a trial-and-error basis with a selected supplier, assessing whether the supplier may be relied upon for firm sales requirements. Once utilities are satisfied with the supplier's performance, they execute contracts based on the lowest bids.

H. 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 certain conditions. The Commission typically requires utilities to return to ratepayers all revenues from capacity-release transactions through the annual true up process.[124] Below is a summary of capacity releases and the associated revenues returned to ratepayers during the true up period.

Table G28: FYE19 Capacity Release[125]

Utility/System	*Capacity Release (Mcf)*	*Capacity Release*	*Revenue Per Mcf*	*Total Gas Costs[126]*	*Revenue as a Percent of Total Gas Costs*
GMG	38,700	$40,892	$1.0566	$6,025,911	0.6786%
Great Plains	847,600	$41,340	$0.0488	$18,070,263	0.2288%
MERC-CON	6,105,100	$301,794	$0.0494	$24,090,158	1.2528%
MERC-NNG	14,668,500	$3,923,186	$0.2675	$135,435,723	2.8967%
CenterPoint	10,870,824	$300,305	$0.0276	$586,074,385	0.0512%
Xcel Gas	2,160,988	$320,417	$0.1483	$319,749,687	0.1002%
MN Total	34,691,712	$4,927,934	$0.1420	$1,089,446,127	0.4523%

Table G28 shows the diversity in Minnesota for capacity-release transactions, capacity portfolios, and individual situations of each gas utility. The revenue from capacity release ranges from $40,892 for GMG to $3,923,186 for MERC-NNG. Utilities returned a total of $4,927,934 to ratepayers in the FYE19 true ups, compared to $2,237,150 in FYE18. The total volumetric capacity-release figures increased from 26,994,291 Mcf in FYE18 to 34,691,712 Mcf in FYE19. The increase in capacity release volume correlates with the data in Table G20, as the actual firm capacity requirement was 87 percent on the peak day in FYE19, compared to 77 percent in FYE18.

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[124] 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.
[125] The data listed in Table G28 is based on the utilities' responses to Department IR 6.
[126] The data listed in the column entitled "Total Gas Costs" is taken from the gas utilities' AAA filings. Total costs incurred include demand and commodity costs.

I. 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 reporting period. Beginning with the FYE99 AAA report, the Commission has required that the gas utilities meet annually with their independent auditors, prior to the auditors' examination of the utility AAA reports, to review the relevant examination procedures and Minnesota Rule 7825.2820.[127] Additionally, the Commission requires gas utilities to direct their independent auditors to include among their procedures a review of any significant variations between purchased volumes (per invoices) and sales volumes (per the general ledger sales journal).[128] The Commission also requires all gas utilities to continue to have independent auditors verify in writing that the actual amounts included in the AAA true up calculations agree with the utilities' accounting books and records.[129]

All gas utilities submitted auditor's reports in compliance with Minnesota Rule 7825.2820. The auditors' reports filed contained no exceptions.

J. LOST-AND-UNACCOUNTED-FOR GAS

Ordering Paragraph 5 in the Commission's April 7, 2011 *Order* for the FYE10 AAA reports 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 and to include a table or attachment showing the data used in calculating 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,[130] the Department developed a comparison of LUF gas by utility. Table G29 presents the Department's summary of LUF gas percentages for FYE19 for Minnesota jurisdictional volumes.

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[127] 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.
[128] Docket No. G,E999/AA-97-1212.
[129] Docket No. G,E999/AA-96-940.
[130] 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: FYE19 Lost-and-Unaccounted-For Gas[131]

Utility/System	*Revenue as a Percent of Total Gas Costs*
GMG	0.70%
Great Plains	0.78%
MERC-CON	(0.90%)
MERC-NNG	(0.98%)
CenterPoint	1.38%
Xcel Gas	1.90%
MN Weighted Avg.	1.24%

A negative LUF number means that a utility, in effect, "found" gas. Consistent with prior reporting periods, Table G29 shows that MERC-NNG and MERC-CON reported negative LUF during FYE19. LUF gas ranged from a negative 0.98 percent for MERC-NNG to a positive 1.90 percent for Xcel Gas. The Department discusses MERC's and Xcel's LUF gas in more detail in the following sections.

1. MERC

MERC has a history of negative LUF,[132] but has been unable to pinpoint a cause for its consistently 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 LUF gas and to subsequently include the results of that investigation in the FYE19 AAA report. MERC submitted its compliance filing on March 26, 2019, proposing a plan to further investigate negative LUF on the NNG PGA. On April 25, 2019, the Department filed comments recommending that MERC conduct the investigation into negative LUF for both the NNG and Consolidated PGA. On May 6, 2019, MERC filed reply comments in Docket No. G999/AA-18-374 agreeing that it would investigate LUF gas on its NNG and Consolidated PGAs.

On pages 2 – 4 of MERC-NNG's AAA Report, MERC described its investigation of its LUF gas and concluded that "…the meter testing program results for MERC have tended toward accuracy readings in excess of 100% (i.e., fast meters) so a negative LUF% would tend to be more likely than a positive LUF%. Given this, and the impact of the pressure factor analysis, MERC determined that the LUF gas of (-0.98%) for the current AAA period was reasonable." MERC's review of the pressure factor, a factor used to adjust for gas pressures as they flow through the meter and to convert the volume of gas measured by the meter into the heating value of gas (BTU), revealed that MERC and NNG use different atmospheric pressures to determine gas volume. All else being equal, this difference would cause MERC to show a consistently negative LUF compared to NNG's measurement of throughput to MERC. Specifically, NNG measures about 1 percent less gas than MERC given the same meter reading and flow.

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

On pages 6 – 7 of MERC-CON's AAA Report, MERC described its investigation of its LUF gas and concluded that "…the meter testing program results for MERC have tended toward accuracy readings in excess of 100% (i.e., fast meters) so a negative LUF% would tend to be more likely than a positive LUF%. Prior years' experiences in the Consolidated PGA area do not show a consistent negative LUF% but rather have fluctuated between positive and negative. An audit of throughput by TBS and a review of BTU factors did not identify any systemic measurement issues or errors. The negative LUF for the Consolidated PGA of (-0.90%) is reasonable and no further analysis is warranted at this time."

MERC further noted in both its NNG and CON AAA Reports that it does not gain or benefit from the negative LUF gas on either system, as the AAA true up process accounts for any differences between actual and billed gas costs.

The Department concludes that MERC complied with the Commission's February 27, 2019 *Order* in Docket No. G999/AA-17-493 and that MERC's investigation has provided some plausible reasons as to why the utility has had, and will likely continue to have, negative LUF gas. The Department raises no additional concerns around MERC's negative LUF gas at this time.

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:

- 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 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. [133]

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. This means that Xcel Gas was charged for more and Xcel Electric was charged for less gas than they used.

In Points 20 – 22 of its November 13, 2019 *Order* in the FYE18 AAA reports, Docket No. G999/AA-18-374, the Commission:

- Approved Xcel's proposed refund to gas customers related to the High Bridge adjustment
- Required Xcel to calculate interest at the prime rate on the 2013-2017 prior period adjustment portion of the High Bridge allocation error ($3,669,040) and include it as a credit no later than its next AAA true up filing (2020 AAA due September 1, 2020)

[133] Xcel Gas's FYE18 AAA Report in Docket No. G999/AA-18-374, Attachment G, pages 2-3.

- Required all regulated utilities, going forward, to identify each non-standard prior-period adjustment made in an annual true up filing, demonstrate whether each adjustment is subject to a Minnesota Rule (e.g., Billing Error Rule, Minn. R. 7820.4000, Approval for Automatic Adjustment of Charges Minn. R. 7825.2920, or some other Rule), and demonstrate the reasonableness of each such adjustment.

The Department will review the High Bridge adjustment credit in Xcel's FYE20 AAA Report.

K. 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

In its FYE14 AAA Report, the Department stated that the reports would be more meaningful if (1) the total gas costs charged for main strikes during the period are reconciled to the amount in the true up and (2) the reports provide the allocation of the gas costs credited to each customer class. Regarding contractor main strikes reporting, all the gas utilities filed the required information.[134]

2. Meter Testing Updates

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

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[134] See GMG's AAA Report, page 5; Great Plains' AAA Report, page 4 and Exhibit C; MERC's AAA Reports, Schedule Q; CenterPoint's AAA Report, Exhibit 9; Xcel Gas' AAA Report, Attachment G, Schedule 7.

Utility	*Meter Testing Update Information*	*AAA Report Page Reference*
GMG	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.	5
Great Plains	The Gas Distribution Standards were again revised in 2018 and 2019. However, there were no updates regarding meter testing to Section 7 of the Gas Distribution Standards.	5
MERC	During the time period of January 1, 2018, through December 31, 2018, MERC tested 6,872 meters as part of its meter testing program. Of those meters tested, 6,488 (94.4%) tested between 98% and 102% accurate. 328 meters (4.8%) tested greater than 102% accurate, 54 meters (0.80%) tested less than 98% accurate, and 2 meters (0.0%) had no test due to the meter being damaged.	5 (CON) & 8 (NNG)
CenterPoint	CenterPoint Energy continued its meter testing and management program in 2018. Meter samples and tests are conducted over a two-year period. All meter lots evaluated passed the accuracy expectations. During 2018 the Company exchanged 4,265 'failed' meters, and year to date through July 2019, 808 meters have been exchanged. Per the meter management program, the work plan for 2019 is set to target an additional 1,170 meters to be exchanged as previously identified meter groups required attention.	24
Xcel Gas	There were no changes regarding meter testing within the annual reporting period of July 1, 2018 and June 30, 2019.	Attachment G, page 11

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

L. 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. 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
- 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, 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. CenterPoint and Xcel Gas have peak-shaving facilities.[135] GMG uses outside resources to assist in managing its gas portfolio.[136] In addition, gas utilities have multiple ways to purchase natural gas. For example, the largest share of natural gas purchases, across all utilities, comes from monthly index-priced gas.[137] Other types of purchases include daily spot-priced gas,[138] daily index-priced gas,[139] or fixed price gas.[140]

M. 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. G999/AA-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 the February 4, 2016 Commission Agenda meeting regarding CenterPoint'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 manage the risks associated with market price 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. Hurricane Katrina is an example of such an event; this hurricane caused severe damage in the southern U.S., including areas with natural gas facilities, and natural gas costs skyrocketed immediately. Hedging can be used to reduce gas price risk by generating a payment when the market price of natural gas moves in an unfavorable (and unpredicted) direction. The objective is not to guarantee the lowest priced gas, but to mitigate price volatility, provide reasonably priced natural gas, and ensure reliability. There are several hedging tools/instruments available in the derivative market such as futures contracts, commodity swaps, "costless" collars, and options.[141]

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[135] Department IR 12. Responses available upon request.
[136] GMG's AAA Report, page 2.
[137] 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.
[138] 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.
[139] 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.
[140] 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.
[141] Definitions and examples of each tool are provided in the glossary that is included as Department Attachment G3.

Three Minnesota LDCs have received Commission approval to recover the costs of financial hedging through their PGAs: CenterPoint, MERC, and Xcel Gas. The Commission also orders financial hedging restrictions based on utility-specific circumstances and information. In separate, periodic variance request filings, the Department performs a thorough analysis in each of the applicable utilities' respective requests to continue recovering hedging costs through their PGAs.

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. The weather during the FYE19 heating season was overall colder than normal, but natural gas prices remained relatively stable during the reporting period, except several weeks of higher prices in November and December 2018. Both at the beginning and end of the FYE19 heating season, natural gas storage levels were below the previous five-year average, and FYE19 net withdrawals from storage were also below the previous five-year average. The following discussion reviews the performance of each utility's hedging program.

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).[142] In Docket No. G011/M-17-85, the Commission granted an extension through June 30, 2021 to the rule variance that allows MERC to recover the costs associated with certain financial instruments through the PGA. Regarding FYE19, MERC stated, in its response to the Department's IR No. 15(H), that there were no changes to the financial hedging program compared to the previous reporting period.

In FYE19, MERC's hedging portfolio provided gas at a lower cost than if it did not hedge, which is consistent with expectations.[143] The Department concludes that MERC accomplished its intended purpose of providing price protection on a portion of its winter gas supplies using the information available at the time it executed its hedges.

CenterPoint: CenterPoint's policy is to provide price stabilization for a portion of its winter supply through hedged gas purchases and storage gas. CenterPoint determines the level of price stabilization each year based on an analysis that incorporates regulatory guidelines (as to volumes and costs), winter price projections, and available portfolio assets.[144] In Docket No. G008/M-15-912, the Commission granted an extension through June 30, 2020 to a rule variance that allows CenterPoint to recover the costs associated with certain financial instruments through the PGA.

In its response to the Department's IR No. 15(H), CenterPoint stated that there was no significant change in its hedging program from the previous year. Regarding its hedging strategy for the FYE19 winter season, CPE stated:

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[142] MERC's AAA Report, PDF page 11, section titled "2018-2019 Gas Procurement Policies".
[143] *Id*., Trade Secret Schedule L.
[144] CenterPoint's AAA Report, page 7.

> Contract storage allowed 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 24.5% 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 24.5 Bcf of total hedged supply and, when combined with 25.7 Bcf of storage volumes, provide stabilized prices for 47.8% of winter gas supplies.
>
> In addition to providing price stability, the price hedges also provided 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 2018 stayed around $3.00 until October when it increased to over $3.25 for the last month. [145]

According to CenterPoint, its hedging program in FYE19 resulted commodity costs passed through the PGA that were, on average, $0.0554 per dekatherm lower than they would have been without hedging. [146] In its response to Department IR 15, CenterPoint explained that its hedging strategy resulted in costs that were overall 11% lower than had it purchased all gas at market price in FYE19. The Department concludes that CenterPoint accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies using the information available 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.[147] 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.[148] In Docket No. G002/M-16-88, the Commission 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.

In its response to the Department's IR 15(H), Xcel Gas stated that there were no changes to the financial hedging program for FYE19.

[145] *Id.*, page 11.
[146] *Id.,* page 24.
[147] Xcel Gas' AAA Report, Attachment A, Schedule 5, page 2.
[148] *Id*., page 3.

Xcel Gas' hedges provided a net gain of approximately $1,669,620 in FYE19.[149] The Department concludes that Xcel Gas accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies using the information available at the time it executed its hedges.

Conclusion and Recommendations: The purpose of the discussed gas utility hedging activity is to reduce price volatility on a portion of the utilities' purchase portfolios; the objective is not to speculate on commodity prices or profit from the results of hedging. The Department concludes that the utilities' hedging program performance appears reasonable. The Department recommends that each utility using hedging, physical or financial, continue to provide in subsequent AAA filings, in a format similar to that in the current docket, an analysis of their hedging activity performance.

IV. SUMMARY OF THE DEPARTMENT'S RECOMMENDATIONS

The Department recommends that the Commission take the following action:

1. Accept the FYE19 annual reports as filed by the gas utilities as being complete as to Minnesota Rules 7825.2390 through 7825.2920.

2. Require that each utility using hedging, physical or financial, continue to provide in subsequent AAA filings, in a format similar to that in the instant docket, an analysis of their hedging activity performance.

3. For Greater Minnesota Gas:

    - Accept GMG's FYE19 true up, Docket No. G001/AA-19-555.
    - Allow GMG to implement its true up, as shown in Department Attachment G5.

4. For Great Plains:

    - Accept Great Plains' FYE19 true up in Docket No. G004/AA-19-542.
    - Allow Great Plains to implement its true up, shown in Department Attachment G6.

5. For MERC:

    - The Department requests that MERC explain in Reply Comments (1) whether and why the $33,283 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE19 over/under cost recovery calculation for the NNG system and (2) whether and why a difference exists between the DDVC/penalty charge amounts shown in MERC-NNG's FYE19 AAA Report and its reply to Department IR 7.

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

- Accept MERC-NNG's FYE19 true up in Docket No. G011/AA-19-517, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.

- Allow MERC-NNG to implement its true up, shown in Department Attachment G8, pending the Department's review of the additional information that the Department requests MERC provide in Reply Comments.

- Accept MERC-CON's FYE19 true up in Docket No. G011/AA-19-518.

- Allow MERC-CON to implement its true up, shown in Department Attachment G9.

6. For CenterPoint:

- Accept CenterPoint's FYE19 true up in Docket No. G008/AA-19-556.
- Allow CenterPoint to implement its true up, shown in Department Attachment G10.

7. For Xcel Gas:

- Accept Xcel Gas' FYE19 true up in Docket No. G002/AA-19-551.
- Allow Xcel Gas to implement its true up, shown in Department Attachment G11.

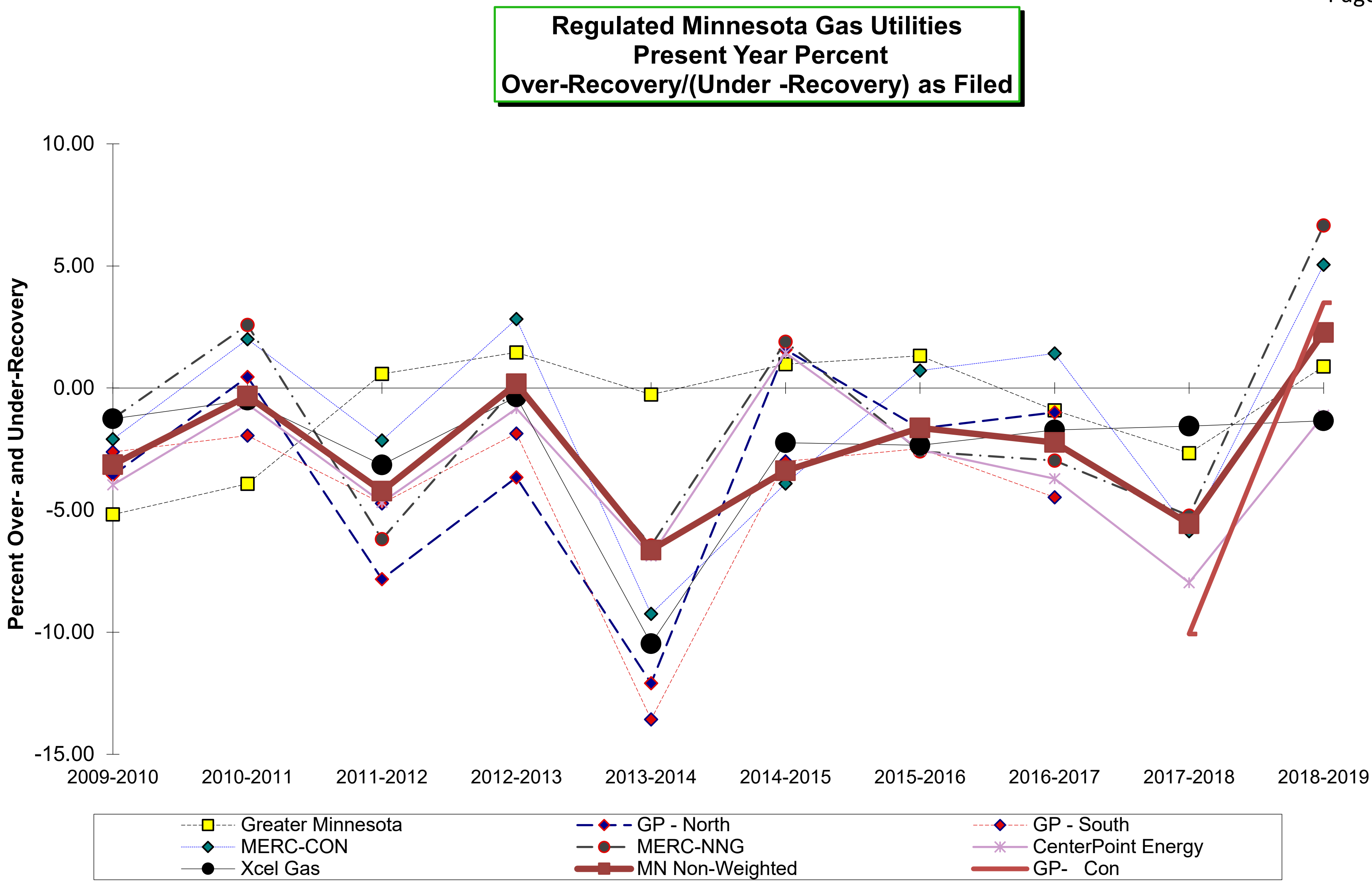
FYE19

RECORDED UNWEIGHTED HEATING DEGREE DAYS

Annual Data											
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2013-2014	Season 2014-2015	Season 2015-2016	Season 2016-2017	Season 2017-2018	Season 2018-2019	2018-2019 vs. Normal (71-00)	2018-2019 vs. Normal (81-10)	2018-2019 vs. Prior 5-Yr. Avg.
DULUTH	9,709	9,444	10,342	9,276	8,186	8,138	9,560	9,448	-2.69%	0.04%	3.82%
INTERNATIONAL FALLS	10,216	10,221	11,511	10,283	8,995	9,088	10,454	10,740	5.13%	5.08%	6.69%
FARGO, ND	9,019	8,802	9,679	8,469	7,172	7,452	8,912	9,810	8.77%	11.45%	17.67%
ST CLOUD	8,744	8,532	9,524	8,143	7,170	7,327	8,687	9,256	5.86%	8.49%	13.29%
MPLS/ST PAUL	7,805	7,580	8,597	7,528	6,283	6,310	7,579	8,024	2.81%	5.86%	10.53%
ROCHESTER	8,150	7,722	8,917	8,068	6,796	6,900	8,065	8,555	4.97%	10.79%	10.40%
SIOUX FALLS, SD	7,683	7,706	8,320	7,568	6,380	6,463	7,569	7,927	3.18%	2.87%	9.19%

Winter Data (November 2018 - March 2019)											
Weather Station	Normals 1971-2000	Normals 1981-2010	Season 2013-2014	Season 2014-2015	Season 2015-2016	Season 2016-2017	Season 2017-2018	Season 2018-2019	2018-2019 vs. Normal (71-00)	2018-2019 vs. Normal (81-10)	2018-2019 vs. Prior 5-Yr. Avg.
DULUTH	7,169	6,952	8,028	7,145	6,046	6,136	7,242	7,109	-0.84%	2.26%	2.74%
INTERNATIONAL FALLS	7,728	7,589	8,869	7,691	6,574	6,750	7,922	7,937	2.70%	4.59%	4.97%
FARGO, ND	7,145	7,589	7,849	6,873	5,758	5,974	7,139	7,680	7.49%	1.20%	14.31%
ST CLOUD	6,853	6,665	7,724	6,583	5,609	5,784	6,865	7,184	4.83%	7.79%	10.30%
MPLS/ST PAUL	6,295	6,108	7,117	6,257	5,121	5,234	6,204	6,446	2.40%	5.53%	7.67%
ROCHESTER	6,437	6,136	7,297	6,553	5,427	5,606	6,408	6,773	5.22%	10.38%	8.23%
SIOUX FALLS, SD	6,157	6,105	6,813	6,278	5,274	5,255	6,075	6,336	2.91%	3.78%	6.68%

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

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*.

<u>Hedging Terms and Examples</u>

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.
2018-2019 True Up
Docket No. G022/AA-19-555

Ten Year Summary of Gas-Cost Recovery

Year Ended 6/30	**Present Year Percent Over (Under) Recovery**	**Cumulative Percent Over (Under) Recovery**
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%	
2018-2019	**0.88%**	**1.30%**
10 Year Average	-0.77%	

Recovery By Class

	(1)	(2)	(3)	(4)	(5)
			(1) - (2)	(3) / (2)	
	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)	PREVIOUS TRUE-UP OVER/(UNDER) ENDING BALANCE
FIRM	$5,289,855	$5,190,164	$99,691	**1.92%**	$11,973
AGRICULTURAL - INTERRUPTIBLE	$417,735	$434,553	($16,818)	**-3.87%**	$11,877
GENERAL - INTERRUPTIBLE	$371,633	$401,194	($29,561)	**-7.37%**	$1,245
TOTAL	**$6,079,223**	**$6,025,911**	**$53,312**	**0.88%**	**$25,095**

	(6)	(7)	(8)	(9)
	(3)+(5)	(6)/(2)		(6)/(8)
	CUMULATIVE OVER/(UNDER) BALANCE	CUMULATIVE %	Estimated Sales (Mcf)	True Up (Refund)/Collection
FIRM	$111,664	**2.15%**	1,205,790	**($0.0926)**
AGRICULTURAL - INTERRUPTIBLE	($4,941)	**-1.14%**	84,960	**$0.0582**
GENERAL - INTERRUPTIBLE	($28,316)	**-7.06%**	124,600	**$0.2273**
TOTAL	**$78,407**	**1.30%**	**1,415,350**	

Greater Minnesota Gas, Inc.
2018-2019 True Up
Docket No. G022/AA-19-555

RECOVERY BY CLASS	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RESIDENTIAL - FIRM	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND COST	$643,775	$571,818	$71,957	12.58%
COMMODITY COST	$2,656,850	$2,685,411	($28,561)	-1.06%
TOTAL	$3,300,625	$3,257,229	$43,396	1.33%
COMMERCIAL - FIRM				
DEMAND COST	$35,920	$31,888	$4,032	12.64%
COMMODITY COST	$148,738	$146,026	$2,712	1.86%
TOTAL	$184,658	$177,914	$6,744	3.79%
INDUSTRIAL - FIRM				
DEMAND COST	$357,680	$332,518	$25,162	7.57%
COMMODITY COST	$1,446,892	$1,422,503	$24,389	1.71%
TOTAL	$1,804,572	$1,755,021	$49,551	2.82%
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	$417,735	$434,553	($16,818)	-3.87%
TOTAL	$417,735	$434,553	($16,818)	-3.87%
IND. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$371,633	$401,194	($29,561)	-7.37%
TOTAL	$371,633	$401,194	($29,561)	-7.37%
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.
2018-2019 True Up
Docket No. G022/AA-19-555

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	$643,775	$571,818	$71,957	12.58%
Commercial - Firm	$35,920	$31,888	$4,032	12.64%
Industrial - Firm	$357,680	$332,518	$25,162	7.57%
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	$1,037,375	$936,224	$101,151	10.80%
COMMODITY COSTS:				
Residential - Firm	$2,656,850	$2,685,411	($28,561)	-1.06%
Commercial - Firm	$148,738	$146,026	$2,712	1.86%
Industrial - Firm	$1,446,892	$1,422,503	$24,389	1.71%
Flexible Rate - Firm	$0	$0	$0	0.00%
Agricultural - Interruptible	$417,735	$434,553	($16,818)	-3.87%
Industrial - Interruptible	$371,633	$401,194	($29,561)	-7.37%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$5,041,848	$5,089,687	($47,839)	-0.94%
DETAIL OF DEMAND RECOVERY				
Viking Zone 1	$332,990	$321,676	$11,314	3.52%
Viking Zone 1-2		$0		
TFX-5	$518,623	$480,653	$37,970	7.90%
TFX- 7	$69,880	$57,942	$11,938	20.60%
TF - 12	$115,882	$116,845	($963)	-0.82%
TF Capacity Release	$0	($40,892)	$40,892	-100.00%
SMS Demand	$0	$0	$0	0.00%
TOTAL	$1,037,375	$936,224	$101,151	10.80%

Great Plains Natural Gas North District
2018-2019 True-Up
Docket No. G004/AA-19-542

Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
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%	
GP-Con	2018-2019	**3.49%**	**4.13%**
	10-Year Average	-3.44%	

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	$14,957,122	$14,449,540	$507,582	**3.51%**	($1,285,788)
INTERRUPTIBLE	$3,744,676	$3,620,723	$123,953	**3.42%**	($413,160)
Total	**$18,701,798**	**$18,070,263**	**$631,535**	**3.49%**	**($1,698,948)**

	(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	$1,418,445	$640,239	**4.43%**	2,731,300	**($0.2344)**
INTERRUPTIBLE	$395,581	$106,374	**2.94%**	1,048,100	**($0.1015)**
Total	**$1,814,026**	**$746,613**	**4.13%**		

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.

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Detail of Current Costs by Class	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)
FIRM	COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
Viking				
FT-A (Zone 1-1; Cat. 3)	$410,555	$394,713	$15,842	4.01%
FT-A (Zone 1-1; Cat. 3)	$256,666	$234,658	$22,008	9.38%
FT-A (Zone 1-1; Cat. 3)	$224,525	$139,025	$85,500	61.50%
FT-A Seasonal	$42,731	$39,656	$3,075	7.75%
BP Contract (Firm Demand)	$4,602	$0	$4,602	0.00%
FT-A - Capacity Release	($23,787)	($23,140)	($647)	2.80%
FT-A - Capacity Release	($1,509)	($10,289)	$8,780	-85.33%
Northern Natural Gas				
TFX - Winter/Seasonal	$1,111,860	$1,031,162	$80,698	7.83%
TFX - Summer	$505,876	$458,151	$47,725	10.42%
TF12 Base - Summer	$153,562	$160,330	($6,768)	-4.22%
TF12 Base - Winter	$197,700	$177,241	$20,459	11.54%
TF12 Variable - Summer	$139,576	$105,220	$34,356	32.65%
TF12 Variable - Winter	$243,144	$233,757	$9,387	4.02%
TF5	$252,781	$234,418	$18,363	7.83%
TFX - Summer	$77,691	$70,485	$7,206	10.22%
TFX - Winter	$533,667	$494,958	$38,709	7.82%
TFX Negotiated Contract - Winter	$131,476	$121,999	$9,477	7.77%
FDD-1 Reservation	$93,232	$85,399	$7,833	9.17%
Interruptible Demand Credit	($381,528)	($344,790)	($36,738)	10.66%
Total Demand	$3,972,820	$3,602,953	$369,867	10.27%
Commodity Cost	$10,984,302	$10,846,587	$137,715	1.27%
TOTAL	$14,957,122	$14,449,540	$507,582	3.51%
INTERRUPTIBLE				
Commodity Cost	$3,399,886	$3,275,933	$123,953	3.78%
Interruptible Demand Charge	$344,790	$344,790	$0	0.00%
TOTAL	$3,744,676	$3,620,723	$123,953	3.42%

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Recovery by Class		(1)	(2)	(3)	(4)
				(1)-(2)	(3)/(2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY ($)	PRESENT YEAR OVER/(UNDER) RECOVERY (%)
FIRM					
	Demand	$3,972,820	$3,602,953	$369,867	10.27%
	Commodity	$10,984,302	$10,846,587	$137,715	1.27%
	Total	$14,957,122	$14,449,540	$507,582	3.51%
INTERRUPTIBLE					
	LMS Demand	$344,790	$344,790	$0	0.00%
	Commodity	$3,399,886	$3,275,933	$123,953	3.78%
	Total	$3,744,676	$3,620,723	$123,953	3.42%

Recovery by Component		(1)	(2)	(3)	(4)
				(1)-(2)	(3)/(2)
		COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY ($)	PRESENT YEAR OVER/(UNDER) RECOVERY (%)
Demand					
	Firm	$3,972,820	$3,602,953	$369,867	10.27%
	Total	$3,972,820	$3,602,953	$369,867	10.27%
Commodity					
	Firm	$10,984,302	$10,846,587	$137,715	1.27%
	Interruptible	$3,744,676	$3,620,723	$123,953	3.42%
	Total	$14,728,978	$14,467,310	$261,668	1.81%

MERC - NNG
2018-2019 True-up
Docket No. G011/AA-19-517

SUMMARY OF GAS COST RECOVERY:

	Year Ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
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%	
MERC-Northern System	**2019**	**6.66%**	**7.02%**
	10-YEAR AVERAGE	-1.35%	

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	$133,896,196	$124,253,439	$9,642,757	**7.76%**	$489,548
SVJ/LVJ/SLV Demand	$36,823	$36,823	$0	**0.00%**	$0
SVI/SVJ/LVI/LVJ/SLVI Commodity	$10,527,375	$11,145,589	($618,214)	**-5.55%**	($8,855)
	$144,460,394	**$135,435,851**	**$9,024,543**	**6.66%**	**$480,693**

	(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	$10,132,305	8.15%	24,554,157	($0.4127)
SVJ/LVJ/SLV Demand	$0	0.00%	1,140	$0.0000
SVI/SVJ/LVI/LVJ/SLVI Commodity	($627,069)	-5.63%	2,819,736	$0.2224
	$9,505,236	7.02%	**27,375,034**	

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
2018-2019 True-up
Docket No. G011/AA-19-517

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		$30,409,142	$20,473,764	$9,935,378	48.53%
	COMMODITY		$103,487,054	$103,779,675	($292,621)	-0.28%
		TOTAL	$133,896,196	$124,253,439	$9,642,757	7.76%
Small & Large Volume Interruptible (SVI/LVI)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$0	$0	$0	0.00%
	COMMODITY		$10,476,626	$11,092,023	($615,397)	-5.55%
		TOTAL	$10,476,626	$11,092,023	($615,397)	-5.55%
Small & Large Volume Joint, Super Large Volume (SVJ/LVJ/SLV)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$36,823	$36,823	$0	0.00%
	COMMODITY		$50,749	$53,566	($2,817)	-5.26%
		TOTAL	$87,572	$90,389	($2,817)	-3.12%

RECOVERY BY COMPONENT

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
			RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY	PRESENT YEAR OVER/(UNDER) RECOVERY
DEMAND	GS		$30,409,142	$20,473,764	$9,935,378	48.53%
DEMAND	SVI/LVI		$0	$0	$0	0.00%
DEMAND	SVJ/LVJ/SLV		$36,823	$36,823	$0	0.00%
		TOTAL	$30,445,965	$20,510,587	$9,935,378	48.44%
COMMODITY	GS		$103,487,054	$103,779,675	($292,621)	-0.28%
COMMODITY	SVI/LVI		$10,476,626	$11,092,023	($615,397)	-5.55%
COMMODITY	SVJ/LVJ/SLV		$50,749	$53,566	($2,817)	-5.26%
		TOTAL	$114,014,429	$114,925,264	($910,835)	-0.79%

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	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%	
MERC-Consolidated	2018-2019	**5.05%**	**5.38%**
	10-YEAR AVERAGE	-1.13%	

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	$23,120,606	$21,874,838	$1,245,768	**5.69%**	$147,081
SVJ Demand	$16,264	$16,264	$0	**0.00%**	$0
SVI/SJV/LVI Commodity	$2,170,867	$2,198,931	($28,064)	**-1.28%**	($69,902)
	$25,307,737	**$24,090,033**	**$1,217,704**	**5.05%**	**$77,179**

	(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	$1,392,849	**6.37%**	4,777,429	**($0.2915)**
SVJ Demand	$0	**0.00%**	696	**$0.0000**
SVI/SVJ/LVI Commodity	($97,966)	**-4.46%**	863,167	**$0.1135**
	$1,294,883	**5.38%**	**5,641,292**	

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		$4,607,295	$3,207,497	$1,399,798	43.64%
	COMMODITY		$18,513,311	$18,667,341	($154,030)	-0.83%
		TOTAL	$23,120,606	$21,874,838	$1,245,768	5.69%
SVI/SJV/LVI						
	DEMAND		$16,264	$16,264	$0	0.00%
	COMMODITY		$2,170,867	$2,198,931	($28,064)	-1.28%
		TOTAL	$2,187,131	$2,215,195	($28,064)	-1.27%

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)		$4,607,295	$3,207,497	$1,399,798	43.64%
DEMAND	SVI/SVJ/LVJ		$16,264	$16,264	$0	0.00%
		TOTAL	$4,623,559	$3,223,761	$1,399,798	43.42%
COMMODITY	General Service (GS)		$18,513,311	$18,667,341	($154,030)	-0.83%
COMMODITY	SVI/SVJ/LVJ		$2,170,867	$2,198,931	($28,064)	-1.28%
		TOTAL	$20,684,178	$20,866,272	($182,094)	-0.87%

CenterPoint Energy
2018-2019 True-Up Docket
No. G008/AA-19-556

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

Year Ended 6/30	PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
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%	
2018-2019	**-1.11%**	**-0.33%**
10-YEAR AVERAGE	-3.09%	

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	$521,358,267	$529,138,104	($7,779,837)	**-1.47%**	$1,931,615	($5,848,222)	**-1.11%**
LGS	$3,342,967	$3,407,720	($64,753)	**-1.90%**	$13,848	($50,905)	**-1.49%**
SVDF	$29,957,139	$30,143,246	($186,107)	**-0.62%**	$66,548	($119,559)	**-0.40%**
LVDF	$24,873,764	$25,456,261	($582,497)	**-2.29%**	$58,935	($523,562)	**-2.06%**
	$579,532,137	**$588,145,331**	**($8,613,194)**	**-1.46%**	**$2,070,946**	($6,542,248)	**-1.11%**

	(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	$4,342,978	($1,505,244)	**-0.28%**	112,503,342	**$0.0134**
LGS	$66,973	$16,068	**0.47%**	645,336	**($0.0249)**
SVDF	$75,650	($43,909)	**-0.15%**	7,801,917	**$0.0056**
LVDF	$136,222	($387,340)	**-1.52%**	6,018,979	**$0.0644**
	$4,621,823	**($1,920,425)**	**-0.33%**	**126,969,574**	

CenterPoint Energy
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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		$90,778,143	$93,415,941	($2,637,798)	-2.82%
PROPANE		$0	$1,228,474	($1,228,474)	-100.00%
COMMODITY		$430,580,124	$434,493,689	($3,913,565)	-0.90%
	TOTAL	$521,358,267	$529,138,104	($7,779,837)	-1.47%
LARGE GENERAL SERVICE					
DEMAND		$365,124	$430,228	($65,104)	-15.13%
PROPANE		$0	$5,655	($5,655)	-100.00%
COMMODITY		$2,977,843	$2,971,837	$6,006	0.20%
	TOTAL	$3,342,967	$3,407,720	($64,753)	-1.90%
SMALL VOLUME DUAL FUEL					
COMMODITY		$29,957,139	$30,143,246	($186,107)	-0.62%
	TOTAL	$29,957,139	$30,143,246	($186,107)	-0.62%
LARGE VOLUME DUAL FUEL					
COMMODITY		$24,873,764	$25,456,261	($582,497)	-2.29%
	TOTAL	$24,873,764	$25,456,261	($582,497)	-2.29%

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			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY COMPONENT			RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) RECOVERY
DEMAND	SVF		$90,778,143	$93,415,941	($2,637,798)	-2.82%
DEMAND	LGS		$365,124	$430,228	($65,104)	-15.13%
PROPANE	SVF		$0	$1,234,129	($1,234,129)	-100.00%
		TOTAL	$91,143,267	$95,080,298	($3,937,031)	-4.14%
COMMODITY	SVF		$430,580,124	$434,493,689	($3,913,565)	-0.90%
COMMODITY	LGS		$2,977,843	$2,971,837	$6,006	0.20%
COMMODITY	SVDF		$29,957,139	$30,143,246	($186,107)	-0.62%
COMMODITY	LVDF		$24,873,764	$25,456,261	($582,497)	-2.29%
		TOTAL	$488,388,870	$493,065,033	($4,676,163)	-0.95%
TOTAL DEMAND AND COMMODITY			$579,532,137	$588,145,331	($8,613,194)	-1.46%

Ten Year Summary of Gas-Cost Recovery:

Year ended 6/30	Present Year Percent Over/(Under) Recovery	Cumulative Percent Over/(Under) Recovery
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%	
2018-2019	**-1.34%**	**-1.32%**
10-YEAR AVG	-2.49%	

Recovery by Class

	(1)	(2)	(3)	(4)	(5)
			(1) - (2)	(3) / (2)	
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)	Present Year True-Up Over/(Under) Beginning Balance
Residential	$169,995,090	$170,370,138	($375,048)	**-0.22%**	($91,475)
Commercial/Industrial Firm	$97,752,840	$98,863,391	($1,110,551)	**-1.12%**	$52,477
Demand Billed Demand	$1,859,049	$1,815,300	$43,749	**2.41%**	$5,417
Demand Billed Commodity	$9,941,192	$10,488,704	($547,512)	**-5.22%**	$38,011
Small Interruptible	$7,817,889	$8,101,909	($284,020)	**-3.51%**	$24,741
Medium & Large Interruptible	$28,094,280	$30,110,245	($2,015,965)	**-6.70%**	$28,016
TOTAL	**$315,460,340**	**$319,749,687**	**($4,289,347)**	-1.34%	**$57,187**

	(6)	(7)	(8)	(9)	(10)
			(7)/(2)		
	Prior Period Adj. Over/(Under)	Total Over/(Under) Collection	Cumulative %	Estimated Sales Therms	**True-Up Factors (Therms) (Refund)/Collection**
Residential	$0	($466,523)	**-0.27%**	381,713,095	**$0.00122**
Commercial/Industrial Firm	$0	($1,058,074)	**-1.07%**	228,502,168	**$0.00463**
Demand Billed Demand	$0	$49,166	**2.71%**	3,291,318	**($0.01494)**
Demand Billed Commodity	$0	($509,501)	**-4.86%**	31,075,202	**$0.01640**
Small Interruptible	$0	($259,279)	**-3.20%**	20,588,002	**$0.01259**
Medium & Large Interruptible	$0	($1,987,949)	**-6.60%**	82,415,415	**$0.02412**
TOTAL	**$0**	**($4,232,160)**	-1.32%	**744,293,882**	

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	$31,861,377	$29,615,777	$2,245,600	7.58%
TU Sch. D, page 4	Commododity & Peak Shaving	$138,133,713	$140,754,361	($2,620,648)	-1.86%
	TOTAL	$169,995,090	$170,370,138	($375,048)	-0.22%
Commercial/Industrial Firm		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$17,976,329	$17,167,217	$809,112	4.71%
TU Sch. D, page 4	Commododity & Peak Shaving	$79,776,511	$81,696,174	($1,919,663)	-2.35%
	TOTAL	$97,752,840	$98,863,391	($1,110,551)	-1.12%
Demand Billed		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$1,859,049	$1,815,300	$43,749	2.41%
TU Sch. D, page 4	Commododity & Peak Shaving	$9,941,192	$10,488,704	($547,512)	-5.22%
	TOTAL	$11,800,241	$12,304,004	($503,763)	-4.09%
Small Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$7,817,889	$8,101,909	($284,020)	-3.51%
	TOTAL	$7,817,889	$8,101,909	($284,020)	-3.51%
Medium & Large Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$28,094,280	$30,110,245	($2,015,965)	-6.70%
	TOTAL	$28,094,280	$30,110,245	($2,015,965)	-6.70%

Recovery by Component

		RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) (%)
Demand	Residential	$31,861,377	$29,615,777	$2,245,600	7.58%
Demand	Commercial/Industrial Firm	$17,976,329	$17,167,217	$809,112	4.71%
Demand	Demand Billed	$1,859,049	$1,815,300	$43,749	2.41%
	TOTAL DEMAND	$51,696,755	$48,598,294	$3,098,461	6.38%
Commodity	Residential	$138,133,713	$140,754,361	($2,620,648)	-1.86%
Commodity	Commercial/Industrial Firm	$79,776,511	$81,696,174	($1,919,663)	-2.35%
Commodity	Demand Billed	$9,941,192	$10,488,704	($547,512)	-5.22%
Commodity	Small Interruptible	$7,817,889	$8,101,909	($284,020)	-3.51%
Commodity	Medium & Large Interruptible	$28,094,280	$30,110,245	($2,015,965)	-6.70%
	TOTAL COMMODITY	$263,763,585	$271,151,393	($7,387,808)	-2.72%

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	$ 3.2236	**1**	$ (0.3168)	-8.95%	$ (0.2583)	-7.42%	$ 3.2542	**1**	$ (0.3367)	-9.38%	$ (0.2530)	-7.21%	-0.94%	**3**
Great Plains***	$ 3.6882	**5**	$ 0.1479	4.18%	$ 0.2063	5.92%	$ 3.6227	**4**	$ 0.0318	0.89%	$ 0.1155	3.29%	1.81%	**5**
MERC-Consolidated	$ 3.2361	**2**	$ (0.3042)	-8.59%	$ (0.2458)	-7.06%	$ 3.2646	**2**	$ (0.3263)	-9.09%	$ (0.2426)	-6.92%	-0.87%	**2**
MERC-NNG	$ 3.7990	**6**	$ 0.2586	7.30%	$ 0.3170	9.11%	$ 3.8293	**6**	$ 0.2384	6.64%	$ 0.3221	9.18%	-0.79%	**1**
CenterPoint Energy****	$ 3.6297	**4**	$ 0.0893	2.52%	$ 0.1477	4.24%	$ 3.6644	**5**	$ 0.0735	2.05%	$ 0.1572	4.48%	-0.95%	**4**
Xcel Gas	$ 3.3150	**3**	$ (0.2253)	-6.36%	$ (0.1669)	-4.79%	$ 3.4079	**3**	$ (0.1830)	-5.10%	$ (0.0993)	-2.83%	-2.72%	**6**
Weighted MN Average	**$ 3.5404**						**$ 3.5909**						**-1.41%**	
Non-Weighted MN Average	**$ 3.4819**						**$ 3.5072**						**-0.72%**	
Standard Deviation	**$ 0.2529**						**$ 0.2343**							

***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	$ 6,079,223	1,564,041	$ 3.8869	**1**	$ (0.3678)	-8.64%	$ (0.3822)	-8.95%	$ 6,025,911	1,564,041	$ 3.8528	**2**	$ (0.4015)	-9.44%	$ (0.3195)	-7.66%	$ 0.0341	0.88%
Great Plains***	$ 18,701,798	3,993,507	$ 4.6831	**5**	$ 0.4284	10.07%	$ 0.4139	9.70%	$ 18,070,263	3,993,507	$ 4.5249	**6**	$ 0.2706	6.36%	$ 0.3526	8.45%	$ 0.1581	3.49%
MERC-Consolidated	$ 25,307,737	6,391,642	$ 3.9595	**2**	$ (0.2952)	-6.94%	$ (0.3096)	-7.25%	$ 24,090,033	6,391,642	$ 3.7690	**1**	$ (0.4853)	-11.41%	$ (0.4033)	-9.67%	$ 0.1905	5.05%
MERC-NNG**	$ 144,460,394	30,011,891	$ 4.8134	**6**	$ 0.5588	13.13%	$ 0.5443	12.75%	$ 135,435,851	30,011,891	$ 4.5127	**5**	$ 0.2584	6.07%	$ 0.3404	8.16%	$ 0.3007	6.66%
CenterPoint Energy****	$ 579,532,137	134,554,392	$ 4.3070	**4**	$ 0.0524	1.23%	$ 0.0379	0.89%	$ 586,074,385	134,554,392	$ 4.3557	**4**	$ 0.1014	2.38%	$ 0.1834	4.39%	$ (0.0486)	-1.12%
Xcel Gas	$ 315,460,340	79,565,500	$ 3.9648	**3**	$ (0.2899)	-6.81%	$ (0.3043)	-7.13%	$ 319,749,687	79,565,500	$ 4.0187	**3**	$ (0.2356)	-5.54%	$ (0.1536)	-3.68%	$ (0.0539)	-1.34%
Mn Weighted Average	**$ 1,089,541,629**	**256,080,973**	**$ 4.2547**						**$ 1,089,446,130**	**256,080,973**	**$ 4.2543**						**$ 0.0004**	**0.01%**
Mn Non-Weighted Average			**$ 4.2691**								**$ 4.1723**						**$ 0.0968**	**2.32%**
Standard Deviation			**$ 0.4009**								**$ 0.3353**							

**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.

Prepared by the Minnesota Commerce Department, Division of Energy Resources

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2018 - June 30, 2019

Company	Tariff Rate Designation	(1) 2017-2018 Annual Customer Charge ($)	(2) 2018-2019 Annual Customer Charge ($)	(3) $ Diff (2) - (1)	(4) % Diff (3)/(1)	(5) 2017-2018 Average Combined Commodity and Demand Charges ($/Mcf)	(6) 2018-2019 Average Combined Commodity and Demand Charges ($/Mcf)	(7) $ Diff (6) - (5)	(8) % Diff (7)/(5)	(9) 2017-2018 Average Non-Gas Commodity Margin ($/Mcf)	(10) 2018-2019 Average Non-Gas Commodity Margin ($/Mcf)	(11) $ Diff (10) - (9)	(12) % Diff (11)/(9)	(13) 2017-2018 Average True-Up ($/Mcf)	(14) 2018-2019 Average True-Up ($/Mcf)	(15) $ Diff (14) - (13)	(16) % Diff (15)/(13)
Greater Minnesota Gas	RS-1	$102.00	$102.00	$0.00	0.00%	$3.9893	$4.0216	$0.0323	0.81%	$4.4433	$4.4433	$0.0000	0.00%	$0.0185	$0.1054	$0.0869	469.73%
Great Plains	N60	$90.00	$90.00	$0.00	0.00%	$4.2575	$4.9467	$0.6892	16.19%	$2.5259	$2.1803	($0.3456)	-13.68%	$0.1584	$0.4341	$0.2757	174.08%
MERC-CON	MERC000002	$118.44	$121.56	$3.12	2.63%	$2.6260	$3.0596	$0.4336	16.51%	$2.5594	$2.5727	$0.0133	0.52%	($0.0652)	$0.1592	$0.2244	-344.35%
MERC-NNG	MERC000001	$118.44	$121.56	$3.12	2.63%	$3.8981	$4.2637	$0.3656	9.38%	$2.5579	$2.5727	$0.0148	0.58%	$0.0944	$0.2040	$0.1097	116.25%
CenterPoint Energy	Residential	$125.25	$119.00	($6.25)	-4.99%	$4.0443	$4.2132	$0.1689	4.18%	$2.2201	$2.1465	($0.0736)	-3.32%	$0.1415	$0.3278	$0.1863	131.66%
Xcel Gas	101	$108.00	$108.00	$0.00	0.00%	$4.1964	$4.6178	$0.4214	10.04%	$1.8591	$1.8571	($0.0020)	-0.11%	$0.0295	($0.0397)	($0.0691)	-234.56%
MN NON-WEIGHTED AVERAGE		$110.36	$110.35	($0.00)	0.00%	$3.84	$4.19	$0.3510	9.15%	$2.69	$2.63	($0.0655)	-2.43%	$0.0628	$0.1985	$0.1356	215.87%

*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, 2018 - June 30, 2019

		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)
		2017-2018	2018-2019			2017-2018	2018-2019			2017-2018	2018-2019			2017-2018	2018-2019		
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	$8.4563	$8.5703	$0.1140	1.35%	7.25	7.75	0.50	6.90%	87.00	93.00	6.00	6.90%	7,052	7,657	605.00	8.58%
Great Plains	N60	$6.9418	$7.5610	$0.6192	8.92%	7.05	7.42	0.37	5.20%	84.60	89.00	4.40	5.20%	8,382	8,483	101.33	1.21%
MERC-CON	MERC000002	$5.1202	$5.7915	$0.6714	13.11%	7.65	8.02	0.36	4.77%	91.80	96.18	4.38	4.77%	30,312	30,584	272.25	0.90%
MERC-NNG	MERC000001	$6.5503	$7.0405	$0.4901	7.48%	7.63	7.91	0.27	3.59%	91.57	94.86	3.29	3.59%	171,573	174,054	2,480.58	1.45%
CenterPoint Energy	Residential	$6.4059	$6.6875	$0.2816	4.40%	7.90	8.23	0.33	4.11%	94.80	98.70	3.90	4.11%	787,172	796,294	9,122.00	1.16%
Xcel Gas	101	$6.0850	$6.4352	$0.3503	5.76%	7.58	8.17	0.58	7.69%	91.00	98.00	7.00	7.69%	421,994	426,335	4,340.58	1.03%
MN NON-WEIGHTED AVERAGE		$6.5932	$7.0143	$0.4211	6.39%	7.51	7.91	0.40	5.36%	90.13	94.96	4.83	5.36%	237,748	240,568	2,820.29	1.19%

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2018 - June 30, 2019

		(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)
		2017-2018	2018-2019			2017-2018	2018-2019			2017-2018	2018-2019		
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	$69.81	$74.92	$5.11	7.32%	$837.70	$899.04	$61.34	7.32%	$1,285.88	$1,301.84	$15.96	1.24%
Great Plains	N60	$56.44	$63.58	$7.14	12.65%	$677.27	$762.93	$85.66	12.65%	$1,061.85	$1,148.54	$86.69	8.16%
MERC-CON	MERC000002	$49.04	$56.55	$7.51	15.31%	$588.47	$678.59	$90.12	15.31%	$835.26	$932.37	$97.11	11.63%
MERC-NNG	MERC000001	$59.85	$65.79	$5.93	9.91%	$718.25	$789.42	$71.17	9.91%	$1,035.49	$1,107.23	$71.74	6.93%
CenterPoint Energy	Residential	$61.04	$64.92	$3.88	6.35%	$732.53	$779.06	$46.53	6.35%	$1,022.08	$1,055.25	$33.17	3.25%
Xcel Gas	101	$55.14	$61.55	$6.41	11.62%	$661.73	$738.65	$76.92	11.62%	$959.90	$1,008.93	$49.04	5.11%
MN NON-WEIGHTED AVERAGE		$58.55	$64.55	$6.00	10.24%	$702.66	$774.61	$71.95	10.24%	$1,033.41	$1,092.36	$58.95	5.70%

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	17,731	-	17,731
Great Plains	12,429	-	12,429
CPE	399,588	-	399,588
MERC-CON	-	-	-
Xcel Gas-MN	20,133	-	20,133
MERC-NNG	61,467	-	61,467
MN Totals	511,348	-	511,348

	DDVC ($)				Percent of Total Costs Incurred		
Company	Positive & Negative	punitive	total	Actual Incurred Gas Cost ($)	Positive & Negative	punitive	total
Greater Minnesota**	$2,117	$1,868	$3,985	$6,025,911	0.0351%	0.0310%	0.0661%
Great Plains	-$5,295	$0	-$5,295	$18,070,263	-0.0293%	0.0000%	-0.0293%
CPE	$168,467	$0	$168,467	$586,074,385	0.0287%	0.0000%	0.0287%
MERC-CON	$0	$0	$0	$24,090,158	0.0000%	0.0000%	0.0000%
Xcel Gas-MN	$19,663	$0	$19,663	$319,749,687	0.0061%	0.0000%	0.0061%
MERC-NNG*	-$141,921	$44,112	-$97,809	$135,435,723	-0.1048%	0.0326%	-0.0722%
MN Totals	$43,031	$45,981	$89,012	$1,089,446,127	0.0039%	0.0042%	0.0082%

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	1,564,041	$ 5,041,848	$ 3.2236	1,564,041	$ 5,089,687	$ 3.2542	-0.94%
Great Plains North	3,993,507	$ 14,728,978	$ 3.6882	3,993,507	$ 14,467,310	$ 3.6227	1.81%
MERC-Consolidated****	6,391,642	$ 20,684,178	$ 3.2361	6,391,642	$ 20,866,272	$ 3.2646	-0.87%
MERC-NNG*****	30,011,891	$ 114,014,429	$ 3.7990	30,011,891	$ 114,925,264	$ 3.8293	-0.79%
CenterPoint Energy***	134,554,392	$ 488,388,870	$ 3.6297	134,554,392	$ 493,065,033	$ 3.6644	-0.95%
Xcel Gas	79,565,500	$ 263,763,585	$ 3.3150	79,565,500	$ 271,151,393	$ 3.4079	-2.72%
MN Weighted Average	256,080,973	$ 906,621,888	$ 3.5404	256,080,973	$ 919,564,959	$ 3.5909	-1.41%
MN Non-Weighted Average			$ 3.4819			$ 3.5072	-0.72%

***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	$	6,079,223	1,564,041	$	3.8869	**1**	$	6,025,911	1,564,041	$	3.8528	**2**	$	0.0341	0.88%
Great Plains***	$	18,701,798	3,993,507	$	4.6831	**5**	$	18,070,263	3,993,507	$	4.5249	**6**	$	0.1581	3.49%
MERC-Consolidated	$	25,307,737	6,391,642	$	3.9595	**2**	$	24,090,033	6,391,642	$	3.7690	**1**	$	0.1905	5.05%
MERC-NNG**	$	144,460,394	30,011,891	$	4.8134	**6**	$	135,435,851	30,011,891	$	4.5127	**5**	$	0.3007	6.66%
CenterPoint Energy	$	579,532,137	134,554,392	$	4.3070	**4**	$	586,074,385	134,554,392	$	4.3557	**4**	$	(0.0486)	-1.12%
Xcel Gas	$	315,460,340	79,565,500	$	3.9648	**3**	$	319,749,687	79,565,500	$	4.0187	**3**	$	(0.0539)	-1.34%
Mn Weighted Average	**$**	**1,089,541,629**	**256,080,973**	**$**	**4.2547**		**$**	**1,089,446,130**	**256,080,973**	**$**	**4.2543**		**$**	**0.0004**	**0.01%**
Mn Non-Weighted Average				**$**	**4.2691**					**$**	**4.1723**		**$**	**0.0968**	**2.32%**
Standard Deviation					**0.4009**						**0.3353**				

**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	$ 5,289,855	1,302,354	$ 4.0618	**2**	$ 5,190,164	1,302,354	$ 3.9852	**2**	$ 0.0765	1.92%
Great Plains-Consolidated**	$ 14,957,122	2,988,138	$ 5.0055	**6**	$ 14,449,540	2,988,138	$ 4.8356	**6**	$ 0.1699	3.51%
MERC-Consolidated*** 2	$ 23,120,606	5,716,390	$ 4.0446	**1**	$ 21,874,838	5,716,390	$ 3.8267	**1**	$ 0.2179	5.69%
MERC-NNG*** 2	$ 133,896,196	27,177,199	$ 4.9268	**5**	$ 124,253,439	27,177,199	$ 4.5720	**5**	$ 0.3548	7.76%
CenterPoint Energy*****	$ 524,701,234	118,383,641	$ 4.4322	**4**	$ 530,600,361	118,383,641	$ 4.4820	**4**	$ (0.0498)	-1.11%
Xcel Gas****	$ 279,548,171	68,278,570	$ 4.0942	**3**	$ 281,537,533	68,278,570	$ 4.1234	**3**	$ (0.0291)	-0.71%
Mn Weighted Average	**$ 981,513,184**	**223,846,292**	**$ 4.3848**		**$ 977,905,875**	**223,846,292**	**$ 4.3686**		**$ 0.0161**	**0.37%**
Mn Non-Weighted Average			**$ 4.4275**				**$ 4.3042**		**$ 0.1234**	**2.87%**

**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).

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	$	789,368	261,687	$	3.0165	**1**	$	835,747	261,687	$	3.1937	**1**	$	(0.1772)	-5.55%
Great Plains***	$	3,744,676	1,005,370	$	3.7247	**5**	$	3,620,723	1,005,370	$	3.6014	**5**	$	0.1233	3.42%
MERC-Consolidated *	$	2,187,131	675,252	$	3.2390	**3**	$	2,215,195	675,252	$	3.2805	**2**	$	(0.0416)	-1.27%
MERC-NNG *	$	10,564,198	2,834,692	$	3.7268	**6**	$	11,182,412	2,834,692	$	3.9448	**6**	$	(0.2181)	-5.53%
CenterPoint Energy*****	$	54,830,903	16,170,751	$	3.3907	**4**	$	55,474,024	16,170,751	$	3.4305	**4**	$	(0.0398)	-1.16%
Xcel Gas****	$	35,912,169	11,286,930	$	3.1817	**2**	$	38,212,154	11,286,930	$	3.3855	**3**	$	(0.2038)	-6.02%
Mn Weighted Average	**$**	**108,028,445**	**32,234,682**	**$**	**3.3513**		**$**	**111,540,255**	**32,234,682**	**$**	**3.4603**		**$**	**(0.1089)**	**-3.15%**
Mn Non-Weighted Average				**$**	**3.3799**					**$**	**3.4728**		**$**	**(0.0929)**	**-2.67%**

*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	1,592,566	0	1,592,566	1,564,041	17,398	0	1,581,439	11,127	0.70%
Great Plains Total Co. #	4,003,039	(82,025)	3,921,014	3,993,507	0	(103,234)	3,890,273	30,741	0.78%
MERC-Consolidated **	6,334,698	74	6,334,772	6,406,825	(15,183)	0	6,391,642	(56,870)	-0.90%
MERC-NNG **	29,940,851	(219,187)	29,721,664	30,030,381	(17,566)	0	30,012,815	(291,151)	-0.98%
CenterPoint Energy	203,887,373	142,877	204,030,250	201,121,048	85,194	0	201,206,242	2,824,008	1.38%
Xcel Gas Mn jurisdiction *	80,775,020	335,416	81,110,436	79,556,722	8,778	0	79,565,500	1,544,936	1.90%
Statewide Totals	326,533,547	177,155	326,710,702	322,672,524	78,621	(103,234)	322,647,911	4,062,791	1.24%

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 Customer Use Gas in column (4) net of Company Use Gas in column (5).

Attachment G20
Supporting Schedule to Tables G19 and G20

	Firm Design Day Demand (Mcf)	Firm Design Day Deliverability **w/ Peak-Shaving** (Mcf)	Actual Peak Day Date (Mcf)	Design-Day Customer Numbers	Actual Firm Peak Day Usage (Mcf)	Annual Firm Throughput (Mcf)	Design-Day Use Per Customer	Peak-Day Use Per Design-Day Customer	Annual Firm Load Factor	Reserve Margin	Annual Firm Requirement %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(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	12,704	14,109	01/29/19	8,410	13,323	1,302,354	1.5106	0.9535	26.78%	11.06%	94.4%
Great Plains #	33,674	35,545	01/29/19	24,240	30,320	3,310,998	1.3892	1.1106	29.92%	5.56%	85.3%
CenterPoint Energy	1,373,000	1,409,596	01/29/19	865,696	1,253,519	125,202,736	1.5860	1.0953	27.36%	2.67%	88.9%
MERC-CON	57,071	57,949	01/29/19	35,653	57,517	4,825,697	1.6007	0.9922	22.99%	1.54%	99.3%
Xcel Gas (Mn JURISDICTION)	735,741	779,864	01/30/19	461,078	644,535	76,070,426	1.5957	1.1415	32.34%	6.00%	82.6%
MERC-NNG	275,681	311,756	01/29/19	198,628	268,848	24,507,563	1.3879	1.0254	24.97%	13.09%	86.2%
Totals	**2,487,871**	**2,608,819**		**1,593,705**	**2,268,062**	**235,219,774**	**1.5611**	**1.0969**	**28.41%**	**4.86%**	86.9%
TOTAL prior year		2,557,214									
Change from prior year		51,605									

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 2018-2019 Annual Automatic Adjustment (AAA) Reports

Docket No. G999/AA-19-401, G004/AA-19-555, G022/AA-19-542, G008/AA-19-556, G011/AA-19-518, G011/AA-19-517, G011/AA-19-517, and G002/AA-19-551

Dated this **26th** day of **April 2022**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-401_AA-19-401
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-401_AA-19-401
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_19-401_AA-19-401
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_19-401_AA-19-401
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-401_AA-19-401
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-401_AA-19-401
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-401_AA-19-401
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-401_AA-19-401
Generic Notice	Residential Utilities Division	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_19-401_AA-19-401
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-401_AA-19-401

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Stasik	richard.stasik@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St - P321 Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-401_AA-19-401
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-401_AA-19-401
Andrew	Sudbury	Andrew.Sudbury@CenterPointEnergy.com	CenterPoint Energy Minnesota Gas	505 Nicollet Mall PO Box 59038 Minneapolis, MN 55459-0038	Electronic Service	No	OFF_SL_19-401_AA-19-401
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-401_AA-19-401
Donald	Wynia	donald.wynia@centerpointenergy.com	CenterPoint Energy	CenterPoint Energy 505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-401_AA-19-401

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_19-517_AA-19-517
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-517_AA-19-517
Michael J	Auger	Michael.auger@ever-greenenergy.com	Ever-Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-517_AA-19-517
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Kathleen M.	Brennan	kmb@mcgrannshea.com	McGrann Shea Carnival, Straughn & Lamb, Chartered	800 Nicollet Mall Ste 2600 Minneapolis, MN 554027035	Electronic Service	No	OFF_SL_19-517_AA-19-517
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-517_AA-19-517
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-517_AA-19-517
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-517_AA-19-517
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_19-517_AA-19-517

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Eichstadt	richard.eichstadt@poet.com	Poet Biorefining - Preston	701 Industrial Dr N PO Box 440 Preston, MN 55965	Electronic Service	No	OFF_SL_19-517_AA-19-517
Darcy	Fabrizius	Darcy.fabrizius@constellation.com	Constellation Energy	N21 W23340 Ridgeview Pkwy Waukesha, WI 53188	Electronic Service	No	OFF_SL_19-517_AA-19-517
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_19-517_AA-19-517
Daryll	Fuentes	energy@usg.com	USG Corporation	550 W Adams St Chicago, IL 60661	Electronic Service	No	OFF_SL_19-517_AA-19-517
David P.	Geschwind	dp.geschwind@smmpa.org	Southern Minnesota Municipal Power Agency	500 First Avenue SW Rochester, MN 55902	Electronic Service	No	OFF_SL_19-517_AA-19-517
Ana	Gonzalez	Ana.Gonzalez@usc.salvationarmy.org	Heat Share - Salvation Army	2445 Prior Ave Roseville, MN 55113	Electronic Service	No	OFF_SL_19-517_AA-19-517
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-517_AA-19-517
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-517_AA-19-517

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Kyto	djkyto@integrysgroup.com	Integrys Business Support	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_19-517_AA-19-517
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_19-517_AA-19-517
Michael	Loeffler	mike.loeffler@nngco.com	Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Electronic Service	No	OFF_SL_19-517_AA-19-517
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-517_AA-19-517
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
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	No	OFF_SL_19-517_AA-19-517
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
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_19-517_AA-19-517
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-517_AA-19-517

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-517_AA-19-517
Generic Notice	Residential Utilities Division	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_19-517_AA-19-517
Jeff	Sande		Bemidji State University	Box 1 Deputy Hall 1500 Birchmont Drive Bemidji, MN 566012699	Paper Service	No	OFF_SL_19-517_AA-19-517
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-517_AA-19-517
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-517_AA-19-517
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_19-517_AA-19-517
Colleen	Sipiorski	Colleen.Sipiorski@wecenergygroup.com	Minnesota Energy Resources Corporation	700 North Adams St Green Bay, WI 54307	Electronic Service	No	OFF_SL_19-517_AA-19-517
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-517_AA-19-517

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Cari	Snaza	cari.snaza@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 55155	Electronic Service	No	OFF_SL_19-517_AA-19-517
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Richard	Stasik	richard.stasik@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St - P321 Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-517_AA-19-517
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-517_AA-19-517
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_19-517_AA-19-517
Casey	Whelan	cwhelan@kinectenergy.com	Kinect Energy Group	605 Highway 169 N Ste 1200 Plymouth, MN 55441	Electronic Service	No	OFF_SL_19-517_AA-19-517
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_19-517_AA-19-517

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James P.	Zakoura	Jim@smizak-law.com	Smithyman & Zakoura Chartered	750 Commerce Plaza II 7400 West 110th Street Overland Park, KS 662102362	Electronic Service	No	OFF_SL_19-517_AA-19-517

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_19-518_AA-19-518
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-518_AA-19-518
Michael J	Auger	Michael.auger@ever-greenenergy.com	Ever-Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-518_AA-19-518
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Kathleen M.	Brennan	kmb@mcgrannshea.com	McGrann Shea Carnival, Straughn & Lamb, Chartered	800 Nicollet Mall Ste 2600 Minneapolis, MN 554027035	Electronic Service	No	OFF_SL_19-518_AA-19-518
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-518_AA-19-518
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-518_AA-19-518
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-518_AA-19-518
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_19-518_AA-19-518

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Eichstadt	richard.eichstadt@poet.com	Poet Biorefining - Preston	701 Industrial Dr N PO Box 440 Preston, MN 55965	Electronic Service	No	OFF_SL_19-518_AA-19-518
Darcy	Fabrizius	Darcy.fabrizius@constellation.com	Constellation Energy	N21 W23340 Ridgeview Pkwy Waukesha, WI 53188	Electronic Service	No	OFF_SL_19-518_AA-19-518
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_19-518_AA-19-518
Daryll	Fuentes	energy@usg.com	USG Corporation	550 W Adams St Chicago, IL 60661	Electronic Service	No	OFF_SL_19-518_AA-19-518
David P.	Geschwind	dp.geschwind@smmpa.org	Southern Minnesota Municipal Power Agency	500 First Avenue SW Rochester, MN 55902	Electronic Service	No	OFF_SL_19-518_AA-19-518
Ana	Gonzalez	Ana.Gonzalez@usc.salvationarmy.org	Heat Share - Salvation Army	2445 Prior Ave Roseville, MN 55113	Electronic Service	No	OFF_SL_19-518_AA-19-518
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-518_AA-19-518
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-518_AA-19-518
David	Kyto	djkyto@integrysgroup.com	Integrys Business Support	700 North Adams PO Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_19-518_AA-19-518
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_19-518_AA-19-518
Michael	Loeffler	mike.loeffler@nngco.com	Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Electronic Service	No	OFF_SL_19-518_AA-19-518
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-518_AA-19-518
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
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	No	OFF_SL_19-518_AA-19-518
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
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_19-518_AA-19-518

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-518_AA-19-518
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-518_AA-19-518
Generic Notice	Residential Utilities Division	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_19-518_AA-19-518
Jeff	Sande		Bemidji State University	Box 1 Deputy Hall 1500 Birchmont Drive Bemidji, MN 566012699	Paper Service	No	OFF_SL_19-518_AA-19-518
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-518_AA-19-518
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-518_AA-19-518
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_19-518_AA-19-518
Colleen	Sipiorski	Colleen.Sipiorski@wecenergygroup.com	Minnesota Energy Resources Corporation	700 North Adams St Green Bay, WI 54307	Electronic Service	No	OFF_SL_19-518_AA-19-518

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-518_AA-19-518
Cari	Snaza	cari.snaza@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 55155	Electronic Service	No	OFF_SL_19-518_AA-19-518
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Richard	Stasik	richard.stasik@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St - P321 Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-518_AA-19-518
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-518_AA-19-518
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_19-518_AA-19-518
Casey	Whelan	cwhelan@kinectenergy.com	Kinect Energy Group	605 Highway 169 N Ste 1200 Plymouth, MN 55441	Electronic Service	No	OFF_SL_19-518_AA-19-518

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_19-518_AA-19-518
James P.	Zakoura	Jim@smizak-law.com	Smithyman & Zakoura Chartered	750 Commerce Plaza II 7400 West 110th Street Overland Park, KS 662102362	Electronic Service	No	OFF_SL_19-518_AA-19-518

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-542_AA-19-542
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_19-542_AA-19-542
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-542_AA-19-542
Generic Notice	Residential Utilities Division	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_19-542_AA-19-542
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-542_AA-19-542

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-551_AA-19-551
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-551_AA-19-551
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_19-551_AA-19-551
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-551_AA-19-551
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-551_AA-19-551
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_19-551_AA-19-551
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_19-551_AA-19-551
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-551_AA-19-551
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_19-551_AA-19-551
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-551_AA-19-551

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-551_AA-19-551
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-551_AA-19-551
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-551_AA-19-551
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-551_AA-19-551
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	Yes	OFF_SL_19-551_AA-19-551
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-551_AA-19-551
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-551_AA-19-551
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_19-551_AA-19-551
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-551_AA-19-551
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-551_AA-19-551

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_19-551_AA-19-551
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-551_AA-19-551
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-551_AA-19-551
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-551_AA-19-551
Generic Notice	Residential Utilities Division	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_19-551_AA-19-551
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-551_AA-19-551
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-551_AA-19-551
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_19-551_AA-19-551
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-551_AA-19-551

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Stasik	richard.stasik@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St - P321 Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-551_AA-19-551
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-551_AA-19-551
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-551_AA-19-551
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-551_AA-19-551
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_19-551_AA-19-551

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-555_AA-19-555
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-555_AA-19-555
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_19-555_AA-19-555
Generic Notice	Residential Utilities Division	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_19-555_AA-19-555
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-555_AA-19-555

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-556_AA-19-556
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Brenda A.	Bjorklund	brenda.bjorklund@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
C. Ian	Brown	office@gasworkerslocal340.com	United Association	Gas Workers Local 340 312 Central Ave SW Minneapolis, MN 55414	Electronic Service	No	OFF_SL_19-556_AA-19-556
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-556_AA-19-556
Steve W.	Chriss	Stephen.chriss@walmart.com	Wal-Mart	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	OFF_SL_19-556_AA-19-556
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-556_AA-19-556
Dean	Dalzell	ddalzell@caphennepin.org	Community Action Partnership of Hennepin County	8800 Highway 7 Ste 401 St. Louis Park, MN 55426	Electronic Service	No	OFF_SL_19-556_AA-19-556
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_19-556_AA-19-556
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_19-556_AA-19-556

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_19-556_AA-19-556
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_19-556_AA-19-556
Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Suite 1400 St. Paul, MN 55101-2134	Electronic Service	Yes	OFF_SL_19-556_AA-19-556
Bruce L.	Hoffarber	bhoffarber@kinectenergy.com	Kinect Energy Group	605 North Highway 169 Ste 1200 Plymouth, MN 55441	Electronic Service	No	OFF_SL_19-556_AA-19-556
Mary	Holly	mholly@winthrop.com	Winthrop & Weinstine, P.A.	225 S Sixth St Ste 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-556_AA-19-556
Daniel	LeFevers	dlefevers@gti.energy	GTI	1700 S Mount Prospect Rd Des Plains, IL 60018	Electronic Service	No	OFF_SL_19-556_AA-19-556
Amber	Lee	Amber.Lee@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Roger	Leider	roger@mnpropane.org	Minnesota Propane Association	PO Box 220 209 N Run River Dr Princeton, MN 55371	Electronic Service	No	OFF_SL_19-556_AA-19-556

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_19-556_AA-19-556
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_19-556_AA-19-556
Michael	Loeffler	mike.loeffler@nngco.com	Northern Natural Gas Co.	CORP HQ, 714 1111 So. 103rd Street Omaha, NE 681241000	Electronic Service	No	OFF_SL_19-556_AA-19-556
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-556_AA-19-556
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	No	OFF_SL_19-556_AA-19-556
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_19-556_AA-19-556
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
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_19-556_AA-19-556
Mike	OConnor	moconnor@ibewlocal949.org	Local 949 IBEW	12908 Nicollet Ave S Burnsville, MN 55337	Electronic Service	No	OFF_SL_19-556_AA-19-556

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_19-556_AA-19-556
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-556_AA-19-556
Generic Notice	Residential Utilities Division	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_19-556_AA-19-556
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_19-556_AA-19-556
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-556_AA-19-556
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_19-556_AA-19-556
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy	505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Richard	Stasik	richard.stasik@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)	231 West Michigan St - P321 Milwaukee, WI 53203	Electronic Service	No	OFF_SL_19-556_AA-19-556

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_19-556_AA-19-556
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_19-556_AA-19-556
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556
Jonathan	Wolfgram	Jonathan.Wolfgram@state.mn.us	Office of Pipeline Safety	445 Minnesota St Ste 147 Woodbury, MN 55125	Electronic Service	No	OFF_SL_19-556_AA-19-556
Donald	Wynia	donald.wynia@centerpointenergy.com	CenterPoint Energy	CenterPoint Energy 505 Nicollet Mall Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-556_AA-19-556