MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	March 30, 2023	Agenda Item 5*

Company	All Commission Regulated Natural Gas Utilities
Docket No.	**G-999/AA-20-172**
	In the Matter of the Review of the 2019-2020 Annual Automatic Adjustment (AAA) Reports and Annual Purchased Gas Adjustment (PGA) True-up Filings
	G-011/AA-20-655
	In the Matter of Minnesota Energy Resources Corporation – NNG's 2020 True-up Filing
	G-011/AA-20-656
	In the Matter of Minnesota Energy Resources Corporation – Consolidated's 2020 True-up Filing
	G-022/AA-20-684
	In the Matter of Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co., Annual True-up Report
	G-008/AA-20-698
	In the Matter of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas Annual True-up Report
	G-004/AA-20-699
	In the Matter of Greater Minnesota Gas, Inc.'s Annual True-up Report for 2020

G-002/AA-20-705

In the Matter of Northern States Power Company's 2020 Annual Purchased Gas Adjustment True-Up Filing

Issues	Should the Commission accept the natural gas utilities' 2019-2020 annual automatic adjustment reports and 2019-2020 annual true-up filings?

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✓ **Relevant Documents**	**Date**
Docket No. G-999/AA-20-172	
Great Plains – Purchased Gas Adjustment Report	August 31, 2020
Greater Minnesota Gas – 2020 Annual Automatic Adjustment Report (Public and Trade Secret)	September 1, 2020
Xcel Energy – 2020 Annual Automatic Adjustment of Charges Report - Gas (Public and Trade Secret)	September 1, 2020
Minnesota Energy Resources Corporation – 2019 2020 Hedge Summary (Public and Trade Secret)	September 1, 2020
Minnesota Energy Resources Corporation – 2020 Annual Automatic Adjustment Report (Trade Secret)	September 1, 2020
Minnesota Energy Resources Corporation – 2020 NNG Annual Automatic Adjustment Report (Public and Trade Secret)	September 1, 2020
Minnesota Energy Resources Corporation – 2020 Consolidated Annual Automatic Adjustment Report	September 1, 2020
CenterPoint Energy – AAA Report 2019-2020 (Public and Trade Secret)	September 1, 2020
Minnesota Energy Resources Corporation – CON Over Under Collection Analysis 2019-2020 (Correction)	September 22, 2020
Department of Commerce – Review of the 2019-2020 AAA Reports	April 26, 2022
CenterPoint Energy – Reply Comments	April 28, 2022
Minnesota Energy Resources Corporation – Reply Comments	May 6,2022
Xcel Energy – Reply Comments	May 6, 2022
Department of Commerce – Response Letter	June 6, 2022

Docket No. G-011/AA-20-655

✓ **Relevant Documents**	**Date**
Minnesota Energy Resources Corporation – Initial Filing	September 1, 2020
Docket No. G-011/AA-20-656	
Minnesota Energy Resources Corporation – Initial Filing	September 1, 2020
Docket No. G-022/AA-20-684	
Great Plains – Initial Filing	August 31, 2020
Docket No. G-008/AA-20-698	
CenterPoint Energy – Initial Filing	September 1, 2020
Docket No. G-004/AA-20-699	
Greater Minnesota Gas – Initial Filing	September 1, 2020
Docket No. G-002/AA-20-705	
Xcel Energy – Initial Filing (Public and Trade Secret)	September 1, 2020

I. INTRODUCTION

Minnesota Rules 7825.2800 – 7825.2830 require that Minnesota Regulated Public Utilities using Automatic Adjustments to recover energy costs file annual reports regarding the operation of these automatic adjustments. Through these reports the Commission verifies whether the utilities have calculated their rate adjustments properly and implemented the rates in a timely manner.

Each year the natural gas utilities file by September 1 annual automatic adjustment (AAA) reports and annual purchased gas adjustment (PGA) true-up filings for the previous July 1 through June 30 fiscal gas year. Every year, the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) performs an extensive review of the utilities' filings.

In the current dockets, the natural gas utilities incurred and recovered total purchased gas costs during the 2019-2020 fiscal gas year of approximately $817,052,166 and $858,256,806[1], respectively. There are no issues in dispute.

II. BACKGROUND

Automatic rate adjustments are covered under Minnesota Rules part 7825.2390 through 7825.2920. Each year the Commission reviews the automatic adjustment of charges reported in the natural gas and electric utilities' annual automatic adjustment (AAA) reports and the natural gas utilities' annual true-up filings. The Commission's review is closely tied to the Department's review of these filings.

On or before September 1, 2019, the following gas utilities submitted their AAA reports in this docket (Docket No. G-999/AA-19-401) and true-up filings (true-ups) in the dockets below:

Greater Minnesota Gas, Inc. (GMG)	G-004/AA-20-699
Great Plains Natural Gas Company (Great Plains)	G-022/AA-20-684
Minnesota Energy Resource Corporation (MERC-Consolidated PGA)	G-011/AA-20-656
Minnesota Energy Resource Corporation (MERC-NNG PGA)	G-011/AA-20-655
CenterPoint Energy (CenterPoint Energy or CPE)	G-008/AA-20-698
Northern States Power Company d/b/a Xcel Energy (Xcel Gas)	G-002/AA-19-551

Every year, the Department prepares a comprehensive review and analysis of the utilities' annual reports and provides comment on other topics that it believes are relevant. Thus, on April 26, 2022, the Department submitted its Review of the 2019-2020 annual automatic adjustment reports (Review). In its Review, the Department recommended the Commission accept the fiscal year annual reports ending on June 30, 2020 (FYE20) as filed by the gas utilities

1 Department's Review. P. 3.

as being complete as in compliance with Minnesota Rules, parts 7825.2390 through 7825.2920. The Department also recommended the Commission accept the annual true-up filings of all the natural gas utilities: GMG, Great Plains, MERC, CPE, and Xcel Gas. However, the Department requested that MERC explain in Reply Comments (1) whether and why the $1,800 of "positive" Daily Deliver Variance Charges (DDVCs) is the only DDVC/penalty charge amount that should be included the FYE20 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 FYE20 AAA Report and its reply to Department IR 7.

Also, the Department provided comments on the gas utilities' 2019-2020 gas costs, peak-day demand profiles and pipeline transportation sources, capacity releases, annual auditor reports, lost-and -unaccounted for gas, contractor main strikes and meter testing, purchasing and hedging practices, as well as other topics.

On April 28, 2022, CenterPoint Energy submitted reply comments.

On May 6, 2022, MERC and Xcel Energy submitted reply comments.

On June 6, 2022, the Department response filed a response letter (Department Response) and accepted MERC's explanations regarding the DDVC/penalty charges and indicated it has no further issues with MERC's 2020 AAA reports/true ups.

III. DISCUSSION

1. Department Review

The Department stated:

> In FYE20, natural gas prices were lower on average than prices during FYE19. The average FYE20 price was just above $2 per Mcf and stayed under $3 per Mcf for all of FYE20 reporting period. The henry hub price[2] in FYE20 ranged between $1.38 and $2.87, beginning the reporting period at about $2.33 per mcf in July 2019 and ending the reporting period around $1.69 per Mcf in June 2020.
>
> Several factors could explain why prices in FYE20 increased low compared to the prior year. First, weather in Minnesota was overall warmer than normal in FYE20, putting downward pressure on gas prices during the heating season. Second, storage levels in November 2020 leading up to the 2019-2020 heating season were at 3.575 Bcf, the highest level since 2017, and, with FYE20 net withdrawals from storage being below the five-year withdrawal average, the end-of-heating-season storage levels of 2.008 Bcf

[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).

were 19 percent higher than the corresponding five-year average;[3] the combination of high storage levels and an early, warmer-than-normal start to the heating season in FYE20 may have contributed to the lower market prices seen in throughout FYE20 heating season. Third, natural gas production continued to increase in FYE20, and these increases in production outpaced the ongoing growth in natural gas consumption. Although commercial and residential natural gas use fell during the warmer-than-normal FYE20 heating season, increases in LNG exports and demand created by natural-gas-powered electric generators more than offset these heating season declines. These FYE20 production and consumption factors also likely contributed to the relatively low natural gas prices during the reporting period.[4]

In FYE20 gas prices dropped and continued to historic lows at the end of 2019-2020 reporting period. The average Henry Hub price dropped to $1.38 MMBtu on June 16, 2020, the lowest daily Henry Hub price (in nominal dollars) since December 1998. Henry Hub prices started out low at the beginning of 2020 and remained low into the 2020 summer months as LNG exports and commercial natural gas demand declined somewhat, due at least in part to the impacts of the COVID-19 pandemic on commercial operations. Low natural gas prices and declines in natural gas demand tend to prompt reductions in natural gas production. Such that in June 2020, dry natural gas production totaled about 90 Bcf/d, down nearly 3.7 Bcf/d from March 2020. Because the reductions in natural gas demand toward the end of FYE20 outpaced the declines in production, the already low Henry Hub prices experienced additional downward pressure at that time.[5]

With the prevalence of shale gas, natural gas production has become more diversified and less reliant on any single basin or area of production. However, there is still a concentration of 51 percent of processing plant capacity along the Gulf coast, making hurricanes an ongoing concern of market interruption.[6] However, in FYE20, there were no major interruptions in natural gas production due to storms.

A. FYE20 AAA Reports and True-Up Filings

The Department noted that, because customers leave and join the utility's system over time, specific customers' mix on a utility's system to probably change somewhat from one year to another year. Therefore, it is probable that some mismatch exists between the specific customers' mix receiving gas service in a given fiscal year and the customers' mix to which the

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[3] EIA Natural Gas Weekly Update, April 23, 2020: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2020/04_16/

[4] Id.

[5] EIA Natural Gas Weekly Update, June 25, 2020: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2020/06_25/

[6] https://www.eia.gov/special/gulf_of_mexico/

refund or charge associated with the prior year's true up is assigned in subsequent years.

The Department stated that gas costs generally comprise the largest component of gas utilities' customer bill, so, while it is not possible to eliminate such mismatches entirely, it is essential that utilities attempt to minimize both over- and under- recoveries to avoid creating substantial inequities among ratepayer generations. As shown in Table G1, the Department found that, for FYE20, gas utilities incurred $817,052,166 in natural gas commodity, transportation, storage, and related purchased gas costs. This amount represents a $272,393,964 decrease, or 25%, from the FYE19 level ($1,089,445,130). The gas utilities recovered approximately $858,256,806 in natural gas costs in base rates and the monthly purchased gas adjustment (PGA). The PGA system over-and-under-recoveries during FYE20 ranged from a 2.18 percent under-recovery for GMG to an over-recovery of 22.50 percent for MERC-NNG.[7]

Table G1: Summary of Gas Utilities' Annual Demand & Commodity Cost Recovery for FYE20[8]

Utility/System	*Gas Cost Recovered*	*Gas Cost Incurred*	*Over/(Under) Recovery*	*Over/(Under) Recovery*
GMG	$5,697,046	$5,824,041	($126,995)	(2.18%)
Great Plains	$13,880,150	$13,730,115	$150,035	1.09%
MERC-CON	$18,581,679	$17,345,334	$1,236,345	7.13%
MERC-NNG[13]	$129,389,759	$105,622,235	$23,767,524	22.50%
CenterPoint	$453,457,709	$446,843,069	$6,614,640	1.48%
Xcel Gas	$237,250,463	$227,687,372	$9,563,091	4.20%
MN Total	$858,256,806	$817,052,166	$41,204,640	5.04%[14]

[Footnotes omitted**]**

The Department recommended that the Commission accept each of the utilities' July 1, 2019-June 30, 2020, fiscal year true-up filings in individual dockets and recommended that each of the utilities be allowed to implement its FYE20 true-ups as shown on Department Attachments G5 through G11.

The Department indicated that it found differences between the Daily Delivery Variance Charges (DDVCs) and other penalty charge amount included in MERC-NNG's AAA Report and its September 22, 2020, response the Department IR 7. Thus, it noted:

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7 Department's Review, p. 3.

8 *Id.*, p. 5

> In MERC-NNG's AAA Report, page 5 of Schedule D.3, MERC included $1,800 of DDVCs in its FYE20 over/under cost recovery calculation for the NNG system; this $1,800 DDVC figure is also included in MERC's response to Department IR 7 as a "positive" DDVC amount. However, in addition to the ($1,800) of positive DDVCs, MERC's response to IR 7 shows that the NNG system incurred a punitive DDVC amount of ($2,378.75) and other penalty charges of ($192,309.30), resulting in a net total of ($196,488.15) for FYE20.

Accordingly, the Department requested that MERC explain in Reply Comments (1) whether and why the $1,800 of "positive" DDVCs is the only DDVC/penalty charge amount that should be included the FYE20 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 FYE20 AAA Report and its reply to Department IR 7.

1) MERC-NNG Reply Comments

In reply, MERC held that Positive and Negative DDVCs, as well as NNG Punitive Charges and Other Penalty Charges should be, and were, all included in the FYE20 over-recovery calculation for the NNG system. Thus, MERC's response to Department Information Request No. 7 reflected all of these charges for FYE20.[9] While the same breakout is not included in the Schedules to MERC's AAA Report filing, those amounts do flow through the over/under cost recovery calculation for the NNG system.

Further MERC held that:

> Differences between MERC's response to Department Information Request No. 7 and the Schedules to MERC's AAA Report reflect only differences in the information presented. The amounts included in MERC's response to Department Information Request No. 7 are included in MERC-NNG's 2019-2020 over-recovery calculation.

Further, MERC stated that all DDVC, punitive DDVC and other penalty charges were properly included in MERC' 2019-2020 gas cost and over-recovery calculation. Thus, MERC noted that:

> Schedule J of MERC-NNG's 2019-2020 AAA Report only reports Negative and Positive DDVCs, which total ($1,800). The amounts from Schedule J is included within the AAA Report gas costs shown on Schedule D.3, as noted by the

[9] In MERC's response to Department Information Request No. 7, MERC provides only Positive and Negative DDVC amounts in response to part a), and provides Positive and Negative DDVCs, as well as NNG Punitive Charges and Other Penalty Charges in response to part b). See Merc Reply Comments, p. 3

Department. Other Penalty Charges of ($192,309.30) and Punitive DDVCs of ($2,378.75) are reflected within Schedule F&G of MERC-NNG's 20192020 AAA Report. The amounts detailed on Schedule F&G are included within the purchase gas costs reflected on Schedule C&D.

2) Department's Response to MERC Reply Comments

Based on its review of MERC's reply comments, the Department accepted MERC explanation and stated, "we raise no further issues with the Company's 2019 and 2020 AAA reports/true ups."

3). Recovery of Gas Cost and True-Up Calculations Correction

MERC-CON requested in its FYE20 True Up Report that it be allowed to return to customers through annual true up factors effective September 1, 2020, the difference between final approved Vikings Gas Transmission (Viking) rates effective January 1, 2020, and the interim Viking rates in effect for the period January 1 – June 30, 2020. The July 1, 2020, settlement agreement in Viking's recent rate case proceeding with the FERC, initially filed June 28, 2019, caused the difference between the Viking rates in FYE20. Because MERC did not adjust its monthly PGA filings for the change in Viking rates, MERC-CON under-charged its customers for actual Viking gas costs incurred January-February 2020 and over-charged its customers for Viking gas costs March-June 2020. The impact of the Viking rate difference on the FYE20 true up is a net refund to customers of approximately $23,000, a relatively small amount. The Department concluded that MERC's proposal is reasonable and does not conflict with the automatic adjustment true up procedures provided for in Minnesota Rule 7825.2700.

Therefore, Department recommended the Commission allow MERC-CON, through its annual true up factors effective September 1, 2020, to adjust for the difference between the final approved Viking Gas Transmission (Viking) rates effective January 1, 2020, and the interim Viking rates in effect for the period January 1 - June 30, 2020.[10]

Also, on September 1, 2020, in Docket No. G011/AA-20-656, MERC filed its 2019-2020 true up for the Consolidated PGA, calculating true-up factors effective September 1, 2020. MERC implemented the filed true-up factors on September 1, 2020, as reflected in the Company's monthly PGA filed in Docket No. G011/AA-20-678. Thereafter, while MERC was preparing its responses to the Department's information request in the instant case discovered an error of a gas true up attributable to the month of April 2020 within its AAA report. Specifically, an April 2020 trade related to ANR pipeline was revised in late May 2020 as a result of change in the agreement terms. When

[10] Relatedly, in Docket No. G011/M-20-702, the Commission approved MERC's request to refund to customers via the MERC-CON PGA for a refund MERC received from Viking in August 2020. The refund MERC received from Viking in August 2020 was also related to the Viking rate case discussed in the instant section.

MERC received ANR invoice in May 2020 for the April trade, the invoice did not reflect the updates to the transaction terms, such that MERC overstated cost by $41,433[11] in its true up calculation. MERC opined that this was an oversight in data collection and inclusion within the purchased gas costs shown in its AAA and not a billing system error and thus:

On September 22, 2020, in Docket No. G011/AA-20-656, MERC submitted a correction to its FYE20 MERC-CON true up after discovering a commodity cost error in the true up calculation. Due to this error, the MERC-CON true up adjustment factors implemented by MERC on September 1, 2020, underrefunded customers for MERC's over-collection of FYE20 costs. In its September 22, 2020, filing, MERC proposed to correct its true up adjustment factors to account for the error and implement those corrected adjustment factors beginning October 1, 2020.

To make this proposed correction, MERC also requested that the Commission grant the utility a variance to Minnesota Rule 7825.2700, which stipulates that "[t]he true-up adjustment must be computed annually for each class by dividing the true-up amount by the forecasted sales volumes and applied to billings during the next 12-month period beginning on September 1 each year…" and Minnesota Rule 7825.2910, Subpart 4, which states "[g]as utilities shall file and implement on September 1 of each year the true-up adjustment…"

According to the Department, MERC in its filing of September 22, 2020, addressed the criteria outlined in Minnesota Rule 7829.3200, which governs rule variances, that allows the Commission to vary its rule if it finds:

i. *Enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule*

MERC explained that not correcting the error through revised true up factors would impose an excessive burden on customers, as the initially filed true up factors would under-refund customers.

ii. *Granting the variance would not adversely affect the public interest*

MERC reasoned that implementing the corrected true up factors would support the public interest by allowing the utility to refund customers the correct amount of over-recovery.

[11] (1,236,344 corrected FYE20 over-recovery – 1,194,911 initially filed FYE20 over-recovery) = $41,433. The overrecovery figures in the preceding calculation are shown in the exhibits labeled "True-up page 1 of 3" in MERC CON's September 22, 2020, correction filing and September 1, 2020, True Up Report filing, respectively, in Docket No. G011/AA-20-656.

iii. Granting the variance would not conflict with standards imposed by law

MERC stated that it is unaware of any conflict with any standards imposed by law.

The Department concluded that it is reasonable and appropriate for MERC to correct the error in its FYE20 true up calculation and to refund customers using the corrected true up adjustment factors, effective October 1, 2020. The Department agrees with MERC that its request for a variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4, meets the three criteria that Minnesota Rule 7829.3200 stipulates must be met for the Commission to grant a rule variance. Therefore, we recommend that the Commission (1) grant MERC a one-time variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4 and (2) approve MERC's proposal to correct its true up adjustment factors, effective October 1, 2020, as shown in MERC's September 22, 2020, correction filing in Docket No. G011/AA-20-656.

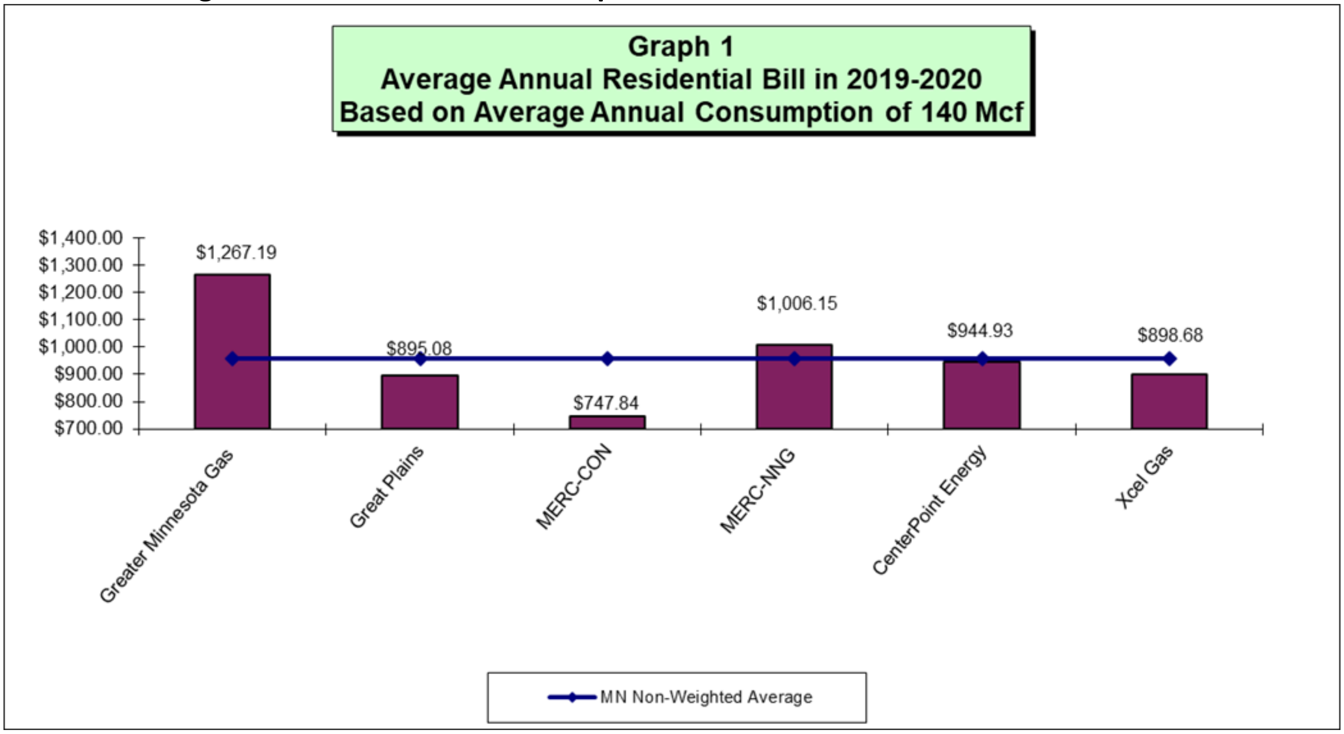
B. Comparison between Minnesota Local Distribution Companies (LDCs)

The Department, as shown on pages 38 through 64 of its Review, conducted further review on cost and operating data/information for all of the regulated natural gas local distribution companies.

Based on information furnished by the utilities in response to its information request No.1, the Department compared the average annual residential customers bill for each of the regulated utilities based on customer charge, per unit energy consumption and average consumption of 140 MCF per year (summarized in Graph 1 below and in Department's attachment G13). Usually, a residential customer pays a fixed monthly charge and a per-unit energy consumption rate, which consist of gas cost and non-gas cost. The gas cost for a firm customer includes both demand costs and commodity costs. The demand cost is the amount a utility pays for the right to reserve pipeline capacity or transportation. Demand levels change only with Commission approval of changes proposed in a miscellaneous demand-entitlement filing.[12] Similarly, when interstate pipelines change the rates that they charge or the cost of gas rates change, Minnesota gas utilities, through the PGAs, automatically pass on these rate changes to their customers.

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

Graph 1: Average Annual Residential Bill in 2019-2020 Based on Average Annual Consumption of 140 Mcf[13]



Graph 1 shows that, based on a consumption level of 140 Mcf, average annual residential bills[14] range from a high of $1,267.19 for customers served by GMG to a low of $747.84 for customers served by MERC-CON.

The Department indicated that, since actual averages for each utility were the result of actual average consumption levels, the amounts on the graph not actual averages for customers on any system. Graph 1 merely intended to provide a baseline usage comparison that remain unchanged between years because consumption remain constant at 140 MCF.

In its Table G15, the Department provided a comparison that ranks the utilities according to annual usage of an average residential customer and the size of the annual bill for an average residential customer.

[13] See Department Review, at 40.

[14] See Department' Review, p. 39; 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.

Table G15: Average Annual Residential Bill and Average Use per Utility for the FYE20 Reporting Period[15]

Utility	*Average Usage Rankings*[16]	*Average Use*[17] *(Mcf)*	*Annual Bill Rankings*	*Total Annual Bill*	*Average Cost per Mcf*[18]	*Annual Customer Charges*
GMG	**1**	83.2	**6**	$794.46	$9.55	$102.00
Great Plains	**1**	83.2	**2**	$574.70	$6.91	$105.42
MERC-CON	**5**	89.3	**1**	$518.21	$5.80	$114.00
MERC-NNG	**3**	86.3	**5**	$664.07	$7.69	$114.00
CenterPoint	**6**	89.3	**4**	$646.84	$7.24	$121.80
Xcel Gas	**4**	89.0	**3**	$610.64	$6.86	$108.00

Table G15 shows that customers served by CenterPoint had highest average consumption of 89.3 MCF, and Greater Minnesota Gas customers had the highest average annual residential bill of $794.46. MERC-NNG's customers had the second highest average annual bill, while Great Plains and GMG customers had the lowest annual consumption.

The Department indicated that many factors affect the size many factors affect the size of the average annual residential utility bills. The amount of gas used by an average residential customer is one factor, which is affected by weather, housing conditions and other variables. The second factor would be the company's cost of gas and a third would be the non-gas rates the company is allowed to charge. There are host of other contributing factors, such as, 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.[19]

As shown in Table G17, the Department also developed a total system average cost of gas analysis using demand cost information provided in the utilities annual true-up reports.

15 See Department Review, at 41.

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

17 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.

18 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

19 See Department Review, at 41.

Table G17: FYE20 Total System Gas Costs (Demand and Commodity)[20]

Utility	*PGA Recovered ($/MMBtu)*	*Rank*	*Current-Period Actual incurred Gas Cost ($/MMBtu)*	*Rank*	*Actual Over/(Under) ($/MMBtu)*	*Percentage Over/(Under) Recovery*
GMG	$3.7329	**5**	$3.8161	**6**	$(0.0832)	(2.18%)
Great Plains	$3.5331	**4**	$3.4949	**4**	$0.0382	1.09%
MERC-CON	$3.0861	**1**	$2.8807	**1**	$0.2053	7.13%
MERC-NNG	$4.5703	**6**	$3.7308	**5**	$0.8395	22.50%
CenterPoint	$3.3737	**3**	$3.3245	**3**	$0.0492	1.48%
Xcel Gas	$3.2342	**2**	$3.1038	**2**	$0.1304	4.20%
MN Weighted Avg.	$3.4670		$3.3005		$0.1664	5.04%
MN Non-Weighted Avg.	$3.5884		$3.3918		$0.1966	5.80%

Total system PGA-recovered and actual-incurred gas costs provides a comparison of the utilities' total system gas costs (demand and commodity). All six PGA systems, except GMG, had an over-recovery of total gas costs during the reporting period, with MERC-NNG reporting the greatest percentage of over-recovery at 22.50 percent. GMG had the highest and MERC-CON had the lowest actual gas cost per MMBtu.

C. Department Review of Gas Utilities' Peak Demand Profiles

For its review of gas utilities' peak demand profiles, the Department utilized the data from responses to its information request to create a summary for FYE20 of each gas utility' peak day demand profile, load factor and reserve margin.

[20] See Department Review, at 44. 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 G19: FYE20 Firm Peak-Day Demand Profiles[21]

Utility	*Firm Design Day Demand (Mcf)*	*Firm Peak-Day Demand Deliverability (Mcf)*	*Annual Firm Throughput (Mcf)*	*Annual Firm Load Factor*	*Reserve Margin*
GMG	14,244	15,275	1,222,851	28.66%	7.24%
Great Plains	34,066	36,945	3,086,396	29.72%	8.45%
MERC-CON	57,065	58,649	5,428,877	33.83%	2.78%
MERC-NNG	280,796	314,349	26,290,450	32.69%	11.95%
CenterPoint	1,399,000	1,478,099	115,732,906	30.88%	5.65%
Xcel Gas	743,696	792,833	71,499,792	38.03%	6.61%
MN Totals	2,528,867	2,696,150	223,261,272	33.13%	6.61%

[Footnotes omitted.]

Table G19 shows that Minnesota's gas utilities exhibit a firm load factor between approximately 29 (GMG) and 38 (Xcel) percent. The weighted average reserve-margin percentage, which includes each utility's contracted transportation and peak-shaving capacity, was 6.61 percent for FYE20, representing a 36 percent increase in the statewide reserve margin compared to the FYE19 4.86 percent average.

The Department noted that it conducted no analysis of the reserve margins in this current filing and supports the continuation of the Commission requirement that reserve margin be included in the annual automatic adjustment report, as this information is useful for comparison purposes.[22]

Staff Comments: Staff notes that reserve margin is an issue dealt with in each utility's annual demand entitlement filing. Each reserved margin is analyzed by the Department and approved by the Commission in the individual demand entitlement filings.

D. Revenue From Curtailment and Balancing Penalties Imposed by Regulated Minnesota Gas Utilities

[21] See Department Attachment G20

[22] Department Review, p. 46.

Utilities must nominate and use interstate pipeline capacity within certain parameter or otherwise face penalties. Because of these utilities established their own guidelines for system use for transportation and interruptible customers and apply penalties to customers that infringe the guidelines when using the gas system.

As such, all Minnesota 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

The Department reviewed the Curtailment and Balancing penalties below.

1. Curtailment Penalties

The Department noted the following:

> 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.[23]

As shown on Table G24, the Department presented a FYE20 summary of the revenue derived from curtailment penalties imposed on interruptible customers.

[23] Department's Review, p. 50.

Table G24: FYE20 Revenue from Curtailment Penalties[24]

Utility/System	*Total Penalties*	*Percent of Total Penalties*	*Total Gas Costs*	*Percent of Total Gas Costs Represented by Penalties*
GMG	$0	0.00%	$5,824,041	0.0000%
Great Plains	$0	0.00%	$13,730,115	0.0000%
MERC-CON	$312	1.07%	$17,345,334	0.0018%
MERC-NNG	$13,061	44.88%	$105,622,234	0.0124%
CenterPoint	$0	0.00%	$446,843,069	0.0000%
Xcel Gas	$15,731	54.05%	$227,687,372	0.0069%
MN Total	$29,104	100.00%	$817,052,165	0.0036%

Table G24 shows that, for FYE20, three utilities charged curtailment penalties on interruptible (or dual fuel) customers totaling $29,104s, or a $1,910,504 decrease from the FYE19 curtailment penalties of $1,939,608. Penalties charged to customers in FYE20 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 costs in the annual true ups.

Staff notes that Department did not address whether it did or not review the utilities unauthorized gas usage and associated penalties like it disclosed in the FYE19 Review. In FYE 19 Review, it disclosed it did not review the unauthorized gas usage because the issue was thoroughly dealt with then in the Commission investigation in Docket No. E,G-999/CI-19-160, related to severe cold weather associated with the polar vortex of FYE19 heating season.

Staff thinks the warmer than normal warm weather in FYE20 with hardly any interruptions, including lack of any destructive storms, make it such that expending any effort in such review seem valueless.

2. Balancing Penalties

Balancing penalties are fines imposed by regulated Minnesota utilities on transportation customers who fail to nominate the daily amount of expected gas use within a certain degree of accuracy. For the same reasons cited 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

[24] The penalties listed in Table G24 are taken from the utilities' responses to Department IR 8. Responses are available upon request. See also Department Review, pp. 50-51.

customer) may face pipeline penalties, which, all else being equal, in turn raises rates for 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 summarizes FYE20 revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers.

Table G25: FYE20 Revenue from Balancing Penalties[25]

Utility/System	*Balancing Penalty Rev.*	*Penalty Rev. as a Percent of Total Penalties*	*Total Gas Costs*	*Penalty Rev. as a Percent of Total Gas Costs*
GMG	$1,115	0.11%	$5,824,041	0.0191%
Great Plains	$22,219	2.25%	$13,730,115	0.1618%
MERC-CON	$0	0.00%	$17,345,334	0.0000%
MERC-NNG	$132,915	13.47%	$105,622,234	0.1258%
CenterPoint	$734,399	74.45%	$446,843,069	0.1644%
Xcel Gas	$95,826	9.71%	$227,687,372	0.0421%
MN Total	$986,474	100.00%	$817,052,165	0.1207%

Table G25 shows FYE20 revenue from balancing penalty revenue collected from transportation customers by gas utilities ranged from $0 (MERC-CON) to $734,399 (CenterPoint). The FYE20 total balancing penalty revenue of $986,474 represents an 8 percent decrease from the FYE19 amount of $1,077,178.

In addition to the above revenue from balancing penalties, NNG pays an annual penalty charge credit to all shippers on its system. As shown in Table 25a, the utilities reported receiving the following credits for FYE20:

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

Table G25a: FYE20 NNG Penalty Charge Credits by Utility[26]

GMG	$2,829,200
Great Plains	$49,890
MERC-CON	$0
MERC-NNG	($196,488)
CenterPoint	($422,853)
Xcel Gas	$186,172
MN Total	$2,445,921

Staff notes that there is an exception to the rule that "if a transportation customer fails to nominate correctly, the utility not the transportation customer would likely face pipeline penalties. According to the Department the exception is where transportation customers sign "End User Balancing Agreements" with the interstate pipeline. In this situation the interstate pipeline directly monitors gas use and directly bills the transportation customer for any imbalance charges.[27]

E. Department Review of LDC Gas Purchasing Practices

In its August 11, 2014, Order in Docket No. G-999/AA-13-600, the Commission requested the Department, in future AAA filings, include a review of gas purchasing practices including:

The Department stated that it analyzed gas procurement in various ways throughout the year, such as:

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

The Department noted 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. GMG uses outside

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

[27] Department Review. P. 51.

resources to assist in managing its gas portfolio.[28] 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.[29] Other types of purchases include daily spot-priced gas,[30] daily index-priced gas,[31] or fixed price gas.[32]

F. Annual Auditor's Report

Minnesota Rule 7825.2820 requires all Minnesota regulated utilities to submit to the Commission an independent auditor's report by September 1 of each year that evaluates the accounting for automatic adjustments for the reporting period. Thus:

> 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.[33] 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).[34] 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.[35]

The Department stated that all gas utilities' auditor's reports contained no exceptions and were in compliance with Minnesota Rule 7825.2820.

G. Lost and Unaccounted for Gas (LUF)

In its April 7, 2011, Order in Docket G-999/AA-09-896, the Commission, requested the Department continue to develop and report a summary and comparison of each of the natural

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[28] GMG's AAA Report, page 2.

[29] 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.

[30] Daily spot-priced gas purchases refer 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.

[31] 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

[32] 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.

[33] 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.

[34] Docket No. G,E999/AA-97-1212

[35] Docket No. G,E999/AA-96-940

gas utility' LUF gas. Accordingly, the Department developed a comparison of LUF gas by utility using the formula from U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration's Form 7100.1-1 to calculate the LUF percentages.[36]

Table G29[37]summarizes LUF gas percentages for FYE20 for Minnesota jurisdictional volumes.

Table G29: FYE20 Lost-and-Unaccounted-For Gas[38]

Utility/System	***Revenue as a Percent of Total Gas Costs***
GMG	(0.61%)
Great Plains	0.10%
MERC-CON	(2.47%)
MERC-NNG	(1.00%)
CenterPoint	1.90%
Xcel Gas	2.16%
MN Weighted Avg.	1.57%

A negative LUF number indicates that a utility, in effect, found gas. LUF gas ranged from a negative 1.00 percent for MERC-NNG and negative 2.47 percent for MERC-CON to a positive 2.16 percent for Xcel Gas. GMG also reported negative LUF for the period.

Staff Note: The Department, in FYE19, asked the utilities to explain their LUF negatives and did not do so in this case (FYE20 Review) but referenced its FYE19 AAA Report in Docket No. G-999/AA-19-401 for additional discussion on MERC's investigation into its negative LUF.[39]

H. Reporting of Contractor Main Strikes and Meter Testing

In its October 11, 2012, Order in Docket G-999/AA-10-885, the Commission required all gas utilities to file, as part of their annual AAA reports, a schedule reflecting contractor main strikes during the corresponding annual period billing 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.

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[36] 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.

[37] Department Review at 56.

[38] See Department Attachment G19 for detailed calculations.

[39] Department Review, p. 56.

1. Contractor Main Strikes Reports

The Department noted that all gas utilities filed the required information for contractor main strikes reporting.[40] However, the Department stated in its FYE14 AAA Report, that the reports filed by the utilities would be more helpful 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.

2. Meter Testing Updates

The Department stated that all the gas utilities filed the required meter testing information with their AAA Reports. Also, the Department reviewed the updates and concluded that the utilities complied with the Commission's Order.

Below the Department provided a short summary of meter testing update information for each utility:[41]

a) Greater Minnesota Gas

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.

b) Great Plains

The Gas Distribution Standards, Section 7 was updated, specifically the combination of the Random Sampling Section and Large Capacity Meters Section. Great Plains has removed the Large Capacity Meters Section and combined small and large meter random sampling in the Random Sampling Section so that all meters are held to the same standards.

c) MERC

In 2019, MERC made a temporary modification to the meter testing program due to the Automated Meter Infrastructure ("AMI") project, which started in 2019. In 2019, MERC temporarily suspended the statistical meter sample testing program during AMI deployment, and focused meter replacement on the meters with large amounts of deficiencies and older meters that may be difficult to do an index exchange on while out in the field. During 2019, and throughout the remainder of the AMI project, MERC is replacing meters that the AMI

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[40] See GMG's AAA Report, pdf page 11; 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.

[41] Department's Review, p. 57.

deployment vendor finds issues with. This temporary modification provides for efficient meter testing while concurrent resources can be utilized during AMI deployment.

From January 1, 2019, to December 31, 2019, MERC tested 3,919 meters as part of its meter testing program. Of those meters tested, 3,625 (92.5%) tested between 98% and 102% accurate. 225 meters (5.7%) tested greater than 102% accurate, 61 meters (1.6%) tested less than 98% accurate, and 8 meters (0.20%) had no test due to the meter being damaged.

d) CenterPoint Energy

CenterPoint continued its meter testing and management program in 2019. Meter samples and tests are conducted over a two-year period and the results of current interval 2019-2020 have been reviewed. All meter lots evaluated are presently passing the accuracy expectations. During 2019 CenterPoint exchanged 1,912 'failed' meters, and year-to-date through June 2020, 465 meters had been exchanged. Per the meter management program, the 2020 work plan was set to target an additional 2,627 meters to be exchanged as previously identified meter groups requiring attention. This work is slightly behind schedule due to COVID-19 restrictions and service protocols.

e) Xcel Gas

There were no changes regarding meter testing within the annual reporting period of July 1, 2019, and June 30, 2020.

I. Minnesota Gas Utilities Hedging Practices

In its August 11, 2014, Order in Docket No. G-999/AA-13-600, the Commission requested the Department provide, in future AAA filings, a review of hedging practices in its review of future annual automatic adjustment reports. Also, given the current state of the natural gas market, at its February 4, 2016, agenda meeting regarding CPE's hedging variance filing in Docket No. G-008/M-15-912, the Commission expressed interest in taking a closer look at utility hedging practices. Thus, the Commission held a Planning Meeting for discussion of hedging practices on June 28, 2016, in which the utilities that participate in hedging (CPE, MERC and Xcel) made presentations.

For background information purposes the Department explained thus:

> 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, as it 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.[42]

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.

The Department noted the impact of weather and other supply issues in the commodity price of natural gas and stated thus:

> 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 FYE20 heating season was overall warmer than normal and, although natural gas prices fluctuated with some volatility between approximately $1.68 and $2.87 Mcf throughout the heating season, prices remained relatively low. Storage levels at the beginning of the FYE20 heating season were at their highest since 2017, and, with FYE20 net withdrawals below the five-year withdrawal average, the end-of-heating-season storage levels were 19 percent higher than the corresponding five-year average.[43]

The Department reviewed the performance of each utilities' hedging program:

1) MERC

A 40%/30%/30% hedging strategy was used by MERC 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). In FYE20, MERC's hedging portfolio provided gas at a higher cost than if it did not hedge.[44]

According to the Department 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.

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[42] Definitions and examples of each tool are provided in the glossary that is included as Attachment G3.

[43] EIA Natural Gas Weekly Update, April 23, 2020: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2020/04_16/

[44] MERC's AAA Report, PDF page 13, section titled "2019-2020 Gas Procurement Policies", Trade Secret Schedule L

2) CenterPoint

CenterPoint held that its hedging 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.[45]

CenterPoint in response to the Department' IR 15 stated there was no significant change in its FYE 20 hedging program from that of FYE19. And regards to hedging strategy, CenterPoint stated thus:

> 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 27.2% of the winter system supplies. Physical base load gas purchases containing price protections were made over several months during the summer using multiple RFP's. CenterPoint Energy purchased 23.1 Bcf of total hedged supply and, when combined with 26.1 Bcf of storage volumes, provide stabilized prices for 51.3% of winter gas supplies. This is slightly higher than plan due to reduction in sales.

CPE also stated that, 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.

CenterPoint's FYE20 hedging program resulted in commodity costs passed through the PGA that were, on average, $0.0242 per dekatherm higher than they would have been without hedging.[46]

The Department concluded 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.

3) Xcel Gas

The overall goal of Xcel's Price Volatility Mitigation Plan was to reduce the exposure to and the magnitude of gas price spikes at a reasonable cost to its customers and not to attempt to outguess the market or to speculate on the future direction of energy prices. The purpose of Xcel's seasonal strategy remained to reduce the potential risk of short-term upsets in the wholesale gas markets and the resulting gas price spikes.[47]

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[45] CenterPoint's AAA Report, page 8.

[46] Id., at p.25.

[47] Xcel Gas' AAA Report, Attachment A, Schedule 5, pages 2-3.

In its response to the Department's IR 15(H), Xcel held that there were no changes to the financial hedging program for FY20 from the previous year and stated that, for FYE20, hedges provided a net financial loss of about $3,175,905.[48]

Accordingly, the Department concluded that the company accomplished its intended purpose to provide reasonable protection on a portion of its winter gas supplies using the information available at the time of execution of its hedges.[49]

Staff infers that based on the Department's disclosures from its review of the utilities' hedging program, that the goal was to reduce price volatility on a portion their purchased portfolios, and devoid of speculative motive on commodity prices or profit from the results of hedging. Staff supports the Department's conclusions that the utilities' hedging seemed reasonable, as well, as the recommendation for 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. DECISION OPTIONS

All Commission Regulated Natural Gas Utilities

1. Accept the FYE20 annual reports as filed by the gas utilities as being complete as to Minnesota Rules 7825.2390 through 7825.2920. (All gas utilities, DOC)

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

Greater Minnesota Gas

3. Accept GMG's FYE20 true up, Docket No. G-001/AA-20-699. (GMG, DOC)

4. Allow GMG to implement its true up, as shown in Department Attachment G5. (GMG, DOC)

Great Plains

5. Accept Great Plains' FYE20 true up, Docket No. G-004/AA-20-684. (Great Plains, DOC)

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48 Id., Attachment G, Trade Secret Schedule 2.

49 Department Review, p. 61.

6. Allow Great Plains to implement its true up, as shown in Department Attachment. (Great Plains, DOC)

MERC

7. Accept MERC-NNG's FYE20 true up in Docket No. G-011/AA-20-655. (MERC, DOC)

8. Allow MERC-NNG to implement its true up, as shown in Department Attachment G8. (MERC, DOC)

9. Accept MERC-CON's FYE20 true up, as corrected in its September 22, 2020, filing in Docket No. G-011/AA-20-656. (MERC, DOC)

10. Allow MERC-CON, through its annual true up factors effective September 1, 2020, to adjust for the difference between the final approved Viking Gas Transmission (Viking) rates effective January 1, 2020, and the interim Viking rates in effect for the period January 1 - June 30, 2020. (MERC, DOC)

11. Grant MERC a one-time variance to Minnesota Rules 7825.2700 and 7825.2910, Subpart 4, and approve MERC's proposal to correct its MERC-CON system true up adjustment factors, effective October 1, 2020, as shown in MERC's September 22, 2020, correction filing in Docket No. G-011/AA-20-656. (MERC, DOC)

12. Allow MERC-CON to implement its true up, as corrected in its September 22, 2020, filing in Docket No. G-011/AA-20-656 and shown in Department Attachment G9. (MERC, DOC)

CenterPoint Energy

13. Accept CenterPoint's FYE20 true up, Docket No. G-008/AA-20-698. (CPE, DOC)

14. Allow CenterPoint to implement its true up, as shown in Department Attachment G10. (CPE, DOC)

Xcel Gas

15. Accept Xcel Gas' FYE20 true up, Docket No. G-002/AA-20-705. (Xcel, DOC)

16. Allow Xcel Gas to implement its true up, as shown in Department Attachment G11. (Xcel, DOC)