MINNESOTA DEPARTMENT OF
COMMERCE

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May 5, 2015

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

RE: Review of 2013-2014 Annual Automatic Adjustment Reports
Docket No. G999/AA-14-580 and Natural Gas Utilities' 2013-2014 Purchased Gas Adjustment (PGA) True-Up Filings (see attached list)

Dear Mr. Wolf:

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

Attached please find the Minnesota Department of Commerce, Division of Energy Resource's (Department or DOC) *Review of the 2013-2014 Annual Automatic Adjustment Reports* (FYE14 AAA Report) for regulated natural gas utilities in Minnesota. The Department also reported on the portfolio analysis (Minnesota Gas Utilities' Purchasing), storage rates analysis (Per-Unit Storage Cost of Gas and Percentage of Storage), and hedging analysis (Minnesota Gas Utilities' Hedging Practices) as requested by the Minnesota Public Utilities Commission (Commission) in its *Order* in Docket No. G999/AA-13-600. Because the FYE14 winter was extremely cold, the Department reported additional information on curtailments.

The Department is available should the Commission have any questions about the FYE14 AAA Report herein provided.

Sincerely,

/s/ MICHELLE ST. PIERRE	/s/ ANGELA BYRNE
Financial Analyst	Financial Analyst
Division of Energy Resources	Division of Energy Resources

MS/AB/ja
Attachments

Docket Numbers for 2013-2014 Gas Utility PGA True-Up Filings:

Docket No. G002/AA-14-736 -	Northern States Power d/b/a Xcel Energy
Docket No. G001/AA-14-742 -	Interstate Power and Light-Gas Utility
Docket No. G011/AA-14-755 -	Minnesota Energy Resource Corporation (MERC) – Northern Natural Gas PGA system
Docket No. G011/AA-14-754 -	Minnesota Energy Resource Corporation (MERC) – Consolidated PGA system
Docket No. G008/AA-14-752 -	CenterPoint Energy
Docket No. G022/AA-14-728 -	Greater Minnesota Gas
Docket No. G004/AA-14-749 -	Great Plains Natural Gas Company

REVIEW OF THE 2013-2014
ANNUAL AUTOMATIC ADJUSTMENT REPORTS

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

MINNESOTA DEPARTMENT OF COMMERCE

DOCKET NO. G999/AA-14-580

MAY 5, 2015

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EXECUTIVE SUMMARY – NATURAL GAS UTILITIES

Since 1985, Minnesota Rules 7825.2800 through 7825.2830 have required public utilities that use automatic adjustments to recover energy costs to file annual reports regarding the operation of the automatic adjustments. The reports allow verification of whether utilities are calculating their rate adjustments properly and are implementing these rates in a timely manner. In reviewing the 2013-2014 (FYE14) filings, the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) incorporated information from prior years' reports, as well as its assessment of the utilities' monthly automatic adjustment filings submitted throughout the FYE14 reporting period.

The Department's FYE14 Annual Automatic Adjustment natural gas report (FYE14 AAA Report) includes analyses of:

- FYE14 automatic adjustment charge calculations filed pursuant to Minnesota Rule 7825.2810, ANNUAL REPORT; AUTOMATIC ADJUSTMENT CHARGES;

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

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

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

All of the regulated local distribution natural gas utilities provided the information necessary to meet the filing requirements. These public utilities are:

- Greater Minnesota Gas, Inc. (Greater Minnesota or GMG);
- Great Plains Natural Gas Company (Great Plains);
- Interstate Power and Light – Gas Utility (Interstate Gas);
- Minnesota Energy Resources Corp. (MERC);

- CenterPoint Energy, a division of CenterPoint Energy Resources Corp. (CenterPoint Energy or CPE); and
- Northern States Power Company d/b/a Xcel Energy - Gas Utility (Xcel Gas).

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

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

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

The Department appreciates the utilities' cooperation in developing the data for these reports. The FYE14 AAA Report builds on the Department's experience and knowledge gained from prior years' reports and is informed by our continuing assessment of the utilities' automatic adjustment filings throughout the reporting period.

In FYE14, average natural gas prices were comparable to but higher than prices during FYE13. Generally, prices increased during the reporting period, due in large part to extreme temperatures, particularly in January and February 2014, along with supply difficulties. The Henry Hub price[1] began the reporting period in the $3.62 per Mcf range during July 2013 and ended the reporting period around $4.59 per Mcf in June 2014.

[1] 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).

Although the industry was relatively unaffected during FYE14 by hurricanes, as noted above, temperatures during the heating season were significantly below normal, particularly during two "Polar Vortexes," which contributed to significantly higher gas usage. The FYE14 annual temperatures were also colder-than-normal.

The sustained cold temperatures, along with the TransCanada pipeline rupture in January 2014 during a Polar Vortex, pipeline operational issues, increased demand for electric generation for space heating and other needs, disruptions in gas production, Northern Natural Gas' (NNG or Northern) Demarcation (Demarc) and Emerson supply point being fully utilized, significant seasonal draw-down of storage, and a shortage of alternative fuels (e.g., propane), kept pressure on the market to keep prices high during the heating season. Natural gas prices and weather are discussed further below.

The FYE14 AAA Report consists of the following sections:

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

I. BACKGROUND AND OVERVIEW

A. OVERVIEW

The Department concludes that all six[1] regulated Minnesota gas utilities met the annual filing requirements, including the provision of information relating to fuel procurement and the annual true-up adjustment. As noted above, these utilities are:

- Greater Minnesota;
- Great Plains;
- Interstate Gas;[2]
- MERC;
- CenterPoint Energy; and
- Xcel Gas.

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

- filing requirements;
- summaries of the gas utilities' 2013-2014 (FYE14) automatic adjustment charge calculations filed pursuant to Minnesota Rule 7825.2810;
- analyses of the gas utilities' true-up filings required by Minnesota Rule 7825.2910, subpart 4;
- supplemental reporting requirements ordered by the Commission in miscellaneous filings; and
- reports required by the Commission's previous AAA Report Orders:
    - August 23, 1999 *Order* in Docket No. G,E999/AA-98-1130;
    - March 12, 2001 *Order* in Docket No. G,E999/AA-99-1095;
    - December 18, 2001 *Order* in Docket No. G,E999/AA-00-1027;
    - December 23, 2002 *Order* in Docket No. G,E999/AA-01-838;
    - August 7, 2003 *Order* in Docket No. E,G999/AA-02-950;
    - August 10, 2004 *Order* in Docket No. E,G999/AA-03-1264;
    - December 7, 2005 *Order* in Docket No. E,G999/AA-04-1279;
    - February 28, 2006 *Order* in Docket No. E,G999/AA-05-1403;
    - February 26, 2008 *Order* in Docket No. E,G999/AA-06-1208;
    - December 8, 2008 *Order* in Docket No. E,G999/AA-07-1130;
    - February 12, 2010 *Order* in Docket No. G999/AA-08-1011;
    - April 7, 2011 *Order* in Docket No. G999/AA-09-896;
    - April 3, 2012 *Order* in Docket No. G999/AA-10-885;
    - October 17, 2013 *Order* in Docket No. G999/AA-11-793;

[1] In Docket No. G011,007/GR-10-977, the Commission approved the consolidation of MERC's two operating divisions, MERC-PNG and MERC-NMU, into MERC on January 1, 2013. In that same order, the Commission approved the consolidation of MERC's four PGA systems into two systems on July 1, 2013.

[2] In Docket No. G,E001/PA-14-107, the Commission issued an Order on December 8, 2014, allowing IPL to sell its gas distribution facilities to MERC; however, for the time period considered in this report, IPL served those customers.

- November 14, 2013 *Order* in Docket No. G999/AA-12-756 (Docket No. 12-756); and
- August 11, 2014 *Order* in Docket No. G999/AA-13-600.

B. FILING REQUIREMENTS

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

<u>Subpart 1</u>

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

<u>Subpart 2</u>

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

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

C. NATURAL GAS PRICES AND WEATHER

1. Gas Prices in FYE14

As noted above, in FYE14, natural gas prices were comparable but higher than prices during FYE13. Generally, Henry Hub prices increased during the entire reporting period, beginning the reporting period (July 2013) near $3.62 per Mcf and ending around $4.59 per Mcf in June 2014, with the lowest price at $3.43 per Mcf in August 2013 and the highest price at $6.00 in February 2014. In FYE14, the prices of alternative fuels (e.g., propane) were extremely high and supplies were extremely tight between mid-January and early February. Further, the market at Emerson became extremely illiquid after the TransCanada explosion in late January and a change in TransCanada's rate design. By March, there was a significant price differential between Canadian and Mid-continent gas. For example, the "Platts Inside FERC" average NNG Demarc Gas Daily Daily (GDD) index price for March 2014 was $7.0235 and for NNG Ventura was $10.3679.

Overall, high prices were attributed to the following factors:

- frequent and sustained cold temperatures during the heating season both in the Midwest and across the country, which contributed to significantly higher gas usage;

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- the pipeline explosion on a line section of the TransCanada pipeline on January 25, 2014 that caused major market reactions at the Ventura gas exchange point;
- pipeline operational issues resulting in operational flow orders by the pipeline companies;
- other market forces, such as increased natural gas demand for electric generation in the Midwest and Northeast regions of the country, disruptions in gas production as a result of well freeze-off, Demarc and Emerson supply points being fully utilized which forced additional supply to come from other sources; and
- significant seasonal draw-down of storage, which kept pressure on the market to keep prices high.

2. Weather in FYE14

Compared to 30-year normal weather from 1981 to 2010, the weather in Minnesota for the entire year of FYE14 was colder than normal across the state. The colder-than-normal annual weather ranged from approximately 7.97 percent colder at the Sioux Falls, South Dakota weather station to approximately 15.48 percent colder in Rochester.

The heating season (November through March) was also colder than normal compared to 30-year normal weather from 1981 to 2010. The colder-than-normal weather ranged from approximately 3.43 percent colder at the Fargo, North Dakota weather station to approximately 18.92 percent colder in Rochester.

According to NNG's March 2014 *Northern Notes*, the weather during the 2013-2014 heating season was 24 percent colder than normal and was the coldest winter Northern had on record (surpassing the winter of 2007-08 that was 7 percent colder than normal). The winter was also persistently cold with all five months colder than normal and without the short periods of warmer temperatures that typically occur at some point during the winter months. There were 49 days when throughput deliveries were in excess of 4 Bcf per day; by contract, in the previous reporting period there were 8 such days. The next highest total for deliveries of 4.0 Bcf days or greater was 23 during the 2007-2009 heating season. During the first seven days of January 2014, four peak market area delivery days were recorded. Market area delivers were:

- 4.831 Bcf on January 2, 2014;
- 4.925 Bcf on January 5, 2014;
- 5.141 Bcf on January 6, 2014; and
- 4.838 Bcf on January 7, 2014.

All of these levels surpassed the previous market area peak of 4.817 Bcf, which was delivered on January 15, 2009. According to NNG, the extremely cold winter provided a unique opportunity for customers to evaluate the appropriate level of pipeline capacity needed to serve their requirements.[3] As a result, Northern stated that it received significant customer interest in acquiring additional or new service. Recent open seasons for the

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[3] *Northern Notes*, August 2014.

combined Northern Lights Zone EF 2014-16 Expansion and Zone ABC 2014-15 expansion, and the West Leg expansion resulted in bids totaling 64,813 Dth/day and 66,110 Dth/day of peak winter Maximum Daily Quantity (MDQ), respectively.

D. GAS UTILITIES SUMMARY

The Department reviewed the gas utilities' filings to:

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

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

Gas-cost recovery generally represents the largest component in the rates and bills that customers pay. Further, as noted above, there can be mismatches in the over- or under-charges in a given year and the true-up amounts in the subsequent year. These mismatches affect rates in subsequent years such that an over-recovery for a certain customer class in one year results in an offsetting decrease in the rates (compared to what would otherwise have been charged) assigned to that customer class in the following year. Likewise, an under-recovery in one year increases rates in the subsequent year, compared to rates that would otherwise have been charged. Thus, it is essential that utilities attempt to minimize both over- and under-recoveries.[4] Section II below provides analyses of the true-ups for individual utilities. Table G1 below summarizes the fuel-cost recovery during the FYE14 reporting period for gas utilities.

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

TABLE G1[5]
Summary of Gas Utilities' Annual Demand and Commodity Cost Recovery
July 1, 2013 through June 30, 2014

Utility	Gas Cost Recovered ($)	Incurred Cost of Gas ($)	Over/(Under) Recovery ($)	Over/(Under) Recovery (%)
Greater Minnesota	$6,343,225	$6,360,602	$(17,377)	(0.27) %
Great Plains				
North	$12,200,500	$13,878,652	$(1,678,152)	(12.09)%
South	$13,322,796	$15,414,790	$(2,091,994)	(13.57)%
Interstate Gas	$10,719,415	$10,119,966	$599,449	5.92%
MERC				
MERC-Consolidated	$36,516,208	$40,238,904	$(3,722,696)	(9.25)%
MERC- NNG	$179,088,264	$191,434,993	$(12,346,729)	(6.45)%
CenterPoint Energy	$840,687,775	$902,777,336	$(62,089,561)	(6.88)%
Xcel Gas	$428,883,794	$479,032,245	$(50,148,451)	(10.47)%
MN Weighted Average	**$1,527,761,977**	**$1,659,257,488**	**$(131,495,511)**	**(7.92)%**

As shown above, seven of the eight PGA systems[6] under-recovered gas costs (demand and commodity), ranging from negative 0.27 percent for Greater Minnesota's PGA to negative 13.57 percent for Great Plains' South PGA. By contrast, Interstate Gas' PGA over-recovered gas costs by 5.92 percent. The weighted average for all Minnesota gas utilities was an under-recovery of 7.92 percent.[7] The Minnesota total cost of gas for FYE14 was $1,659,257,488 (about $1.6 billion) and for FYE13 was $1,063,629,628 (about $1.1 billion), which represents an increase in gas costs of $595,627,860 (about $595 million), or approximately 56 percent from the level in FYE13. Table G1a below presents a comparison of FYE14 gas costs to the nominal gas costs in past reporting periods.

5 The information for Table G1 can be found in each of the utilities' true-ups, which have been included as Department Attachments G5 through G11.

6 The Department notes that "gas utility" and "PGA system" are, at times, interchangeable in this Report.

7 The Minnesota weighted-average amount is calculated by dividing the under-recovery amount by the total cost of gas.

TABLE G1a
Summary of Gas Utilities' Annual Demand and Commodity Cost Incurred

Report Period	Total Cost ($)	FYE14 Increase/(Decrease) Compared to Previous Yrs.
FYE14	$1,659,257,488	
FYE13	$1,063,629,628	56%
FYE12	$899,685,483	84%
FYE11	$1,228,496,903	35%
FYE10	$1,290,861,146	29%
FYE09	$1,667,839,793	(1)%
FYE08	$2,183,027,141	(24)%
FYE07	$1,904,701,880	(6)%
FYE06	$2,190,228,230	6%
FYE05	$1,772,068,663	17%

Table G1a indicates that the total cost of gas which includes demand and commodity for FYE14 was significantly higher than the cost of natural gas in all of the reporting periods over the last ten years except for FYE07, FYE08, and FYE09.

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

TABLE G2
Percent Over-Recovery/(Under-Recovery)
FYE05 through FYE14[8]

Utility	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	10yr-Ave.	2013-2014[9] Cum.
GMG	(2.42)	(1.37)	(6.44)	3.25	(4.96)	(5.18)	(3.92)	0.58[10]	1.46	(0.27)	(1.93)	(0.43)
Great Plains												
North[11]	(1.94)	(4.42)	(4.37)	0.67	(0.36)	(3.57)	0.45	(7.83)	(3.66)	(12.09)	(3.71)	(11.48)
South	(0.92)	(3.03)	(3.47)	(1.56)	(3.34)	(2.62)	(1.95)	(4.73)	(1.86)	(13.57)	(3.71)	(12.97)
Interstate Gas	(2.36)	(2.99)	(1.20)	1.67	5.42	(5.17)	(0.65)	(5.61)	3.76	5.92	(0.12)	5.63
MERC												
Consolidated	2.60	(1.56)	(2.22)	1.94	3.85	(2.09)	2.00	(2.15)	2.82	(9.25)	(0.41)	(11.65)
NNG	2.46	(1.60)	(3.27)	1.21	1.21	(1.25)	2.58	(6.19)	0.08	(6.45)	(1.23)	(6.12)
CenterPoint	(0.61)	(1.34)	0.06	(0.44)	1.17	(3.96)	(0.66)	(4.68)	(0.84)	(6.88)	(1.82)[12]	(5.62)
Xcel Gas	(1.77)	(1.35)	0.32	(1.75)	(0.23)	(1.26)	(0.50)	(3.15)	(0.36)	(10.47)	(2.05)	(10.43)

As shown in Table G2, all of the PGA systems except GMG and Interstate Gas experienced cumulative under-recoveries in excess of five percent during the FYE14.[13] Interstate Gas' cumulative over recovery was in excess of five percent. The ten-year average from FYE05 through FYE14 shows an under-recovery for all of the gas utilities. The Department's analysis of the over- or under-recovery for each utility is presented below in Section II.

[8] See Department Attachment G2 graph comparing historical true-up adjustments.

[9] The figures for this column are included in Department Attachment G5 through G11 in each of the utility's true-ups. The cumulative over- or under-recovery is a calculation based on prior years' true-ups and the present year's true-up.

[10] This percentage was corrected to a positive rather than negative amount.

[11] In February 2004, Great Plains' monthly PGA for the Crookston district was merged with its monthly PGA for the North-4 district to become the North District PGA.

[12] The figure of (1.39) percent is based on the average percent over-under-recoveries of CenterPoint Energy's Northern and Viking PGAs for the true-up periods 2003-2004 and the combined PGAs for FYE05 through FYE13.

[13] The Department specifies the five percent threshold per Minnesota Rule 7825.2920, subpart 2, concerning adjustment errors.

Table G3 provides a summary of the current period's over- or under-recoveries. This table illustrates over- or under-recoveries for firm and interruptible classes as a whole and by pipeline system for equivalent PGA systems during the FYE14 true-up period.

TABLE G3
Percent Over-Recovery/(Under-Recovery)
FYE14 by Firm and Interruptible Classes

Utility	Firm%[14]	Interruptible%	Total%
Greater Minnesota	(0.54)%	2.63%	(0.27)%
Great Plains			
North	(12.89)%	(9.74)%	(12.09)%
South	(13.94)%	(12.75)%	(13.57)%
Interstate Gas	7.28%	(0.58)%	5.92%
MERC			
Consolidated	(9.49)%	(7.74)%	(9.25)%
NNG	(6.10)%	(10.79)%	(6.45)%
CenterPoint Energy	(7.00)%	(6.30)%	(6.88)%
Xcel Gas	(9.77)%	(15.24)%	(10.47)%
MN Weighted Avg.	**(7.75)%**	**(8.90)%**	**(7.92)%**

Table G3 shows what is noted above, that during the reporting period, one PGA system (Interstate Gas) reported a firm over-recovery in excess of five percent of actual costs. All of the remaining PGA systems except GMG reported firm under-recoveries in excess of five percent. Table G3 also shows that all PGA systems except GMG and Interstate Gas experienced an under-recovery of interruptible costs in excess of five percent. GMG experienced an over-recovery of interruptible costs of 2.63 percent.

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

[14] MERC's interruptible figures include the Joint customers' firm requirements since the Joint customers are not considered firm on the peak day.

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

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

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

Each of these factors is discussed below.

1. Weather Variance – Weather is typically the largest factor affecting the level of firm natural gas sales volumes. Therefore, weather can significantly affect the recovery of both demand and commodity gas costs.[15]

   There are seven area weather stations used for Minnesota data.[16] The Department compiled weather data from each of those stations as summarized below and in more detail in Attachment G1. Compared to 30-year normal weather from 1981 to 2010, [17] the weather in Minnesota for FYE14 as a whole was significantly colder than normal across the state. For the reporting period, the colder-than-normal weather ranged from approximately 7.97 percent colder at the Sioux Falls, So. Dakota station to approximately 15.48 percent colder in Rochester as follows:

FYE14 Weather in Minnesota	
Duluth	9.51%
International Falls	12.62%
Fargo, No. Dakota	9.96%
St. Cloud	11.63%
Minneapolis/St. Paul	13.42%
Rochester	15.48%
Sioux Falls, So. Dakota	7.97%

   The weather in Minnesota for the heating season November to March was also significantly colder than normal compared to 30-year normal weather from 1981 to 2010. The colder-than-normal weather ranged from approximately 3.43 percent colder

15 Demand gas costs represent the cost of pipeline capacity to transport firm gas supplies. Commodity gas costs represent the cost of the product.

16 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).

17 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.

at the Fargo, No. Dakota weather station to approximately 18.92 percent colder in Rochester as follows:

Winter of 2014 Weather in Minnesota	
Duluth	15.48%
International Falls	16.87%
Fargo, No. Dakota	3.43%
St. Cloud	15.89%
Minneapolis/St. Paul	16.52%
Rochester	18.92%
Sioux Falls, So. Dakota	11.60%

In terms of the shoulder months (October and April) conditions at each weather station, except for Sioux Falls, So. Dakota, were significantly colder than normal in April 2014.

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

Colder-than-normal weather during FYE14 meant that utilities generally over-recovered demand costs from firm customers (interruptible customers are not charged for demand costs). During FYE14, all of the eight PGA systems over-recovered demand costs, ranging from an over-recovery of 10.00 percent for CenterPoint Energy to 39.84 percent for Interstate Gas. Each PGA system over/(under) recovered its demand costs by the following percentages:

FYE14 Demand Costs As Filed[18]	
Greater Minnesota	18.46%
Great Plains North	19.34%
Great Plains South	20.89%
Interstate Gas[19]	39.84%
MERC-Consolidated	27.79%
MERC-NNG	24.46%
CenterPoint Energy[20]	10.00%
Xcel Gas	15.11%
MN Weighted Average	15.45 %

18 The percentages include revenue such as capacity release, curtailment, and off-system sales which increased the over recovery percentages.

19 The percentage for Interstate Gas represents Assigned Demand.

20 The true up has an under-recovery of 0.22 percent, including propane and excluding revenue credits. The 10 percent shown here includes demand related Off-system sales and curtailment revenue. See CPE's true up report, page 14.

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

Recovery of commodity costs is also affected by weather, as well as price fluctuations. The gas-commodity portion of rates is generally based on price estimates made during the week prior to the beginning of each month. Thus, an unexpected cold period during the middle of a month, following normal weather in the last week in the preceding month, generally will lead to an under-recovery of higher-than-expected gas commodity costs. Conversely, a cold period during the last week of the month followed by normal weather generally leads to an over-recovery of commodity costs if actual commodity gas costs correspondingly decline. Similarly, a prolonged period of either warmer-than-normal or colder-than-normal weather at the beginning of the winter heating season can impact natural gas prices during the remainder of the heating season.

Due to the colder-than-normal weather experienced during the winter, all things being equal, commodity costs should have been over recovered. However, as discussed above in Section I.C, prices during the heating season were volatile and higher than expected. Thus, during FYE14, all of the PGA systems under-recovered commodity costs, ranging from 0.08 percent for Interstate Gas to 17.53 percent for Great Plains South. Each PGA system over/(under) recovered its commodity costs by the following percentages:

FYE14 Commodity Costs As Filed[21]	
Greater Minnesota	(2.32)%
Great Plains North	(16.31)%
Great Plains South	(17.53)%
Interstate Gas[22]	(0.08)%
MERC-Consolidated	(13.13)%
MERC-NNG	(13.72)%
CenterPoint Energy	(7.47)%
Xcel Gas	(13.38)%
MN Weighted Average	(10.07)%

2. <u>Calculation of the monthly volumetric demand-cost recovery rate.</u>

Changes in demand costs – In general, demand costs are the costs of reserving pipeline capacity to transport firm gas supplies.[23] Since the current non-gas base rate for most utilities' customers generally does not include a separate demand charge,

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[21] The percentages include revenue such as capacity release, curtailment, and off-system sales which increased the over recovery percentages.

[22] The percentage for Interstate Gas represents only commodity and not allocated demand which was over recovered by 22.81 percent.

[23] 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 demand or commodity.

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 FERC-approved pipeline rates[24] to the Commission's approved demand entitlement level of the utility. Demand entitlements are normally contracted for with pipelines 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.[25]

Further, sales are generally much greater during winter than during summer months. If the recovery of annual demand costs during the winter months is lower due to warmer-than-normal weather during the heating season, there generally will be an under-recovery of demand costs, all else being equal.[26] This under-recovery occurs because the winter months are when the greatest percentage of cost recovery generally occurs.

Test-Year Sales Volumes – The monthly PGA calculation is based on an estimated sales figure, calculated according to Minnesota Rule 7825.2700, subpart 5. As explained above, a utility must use the test-year demand volumes from its most recent general rate case for three years following its rate case. Afterwards, the utility must use annual demand volumes. Whenever sales increase over time, use of test-year sales volumes results in an over-recovery of the demand costs, all else being equal.

3. <u>Capacity Release Credits</u> – A utility may sell its contracted pipeline capacity ("capacity-release transaction") if the utility determines that a portion of reserved capacity will not be needed to serve its customers. The Commission requires utilities to return to firm ratepayers all revenue from these capacity-release transactions. The monthly PGA and/or the annual true-up amount are credited, thereby reducing the recovery of demand costs. 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.

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24 If the pipeline is intrastate then the Commission approved rates apply.

25 The following examples of changes that affect the utility's demand costs are changes in the:

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

26 Likewise, if annual demand costs estimated during the winter months are higher than annual demand costs during other months, there generally will be an over-recovery of demand costs, all else being equal.

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

5. Prorating of customer bills – When a utility reads a customer's meter in the middle of the month, the registered usage represents consumption from two different PGA (calendar month) periods. Thus, the utility must bill the customer based on an estimate of the consumption that took place during each PGA period. Because this prorated bill will not exactly match the true consumption that took place each month, except by coincidence, over- or under-recoveries typically will result.

6. The three-cent rule – Minnesota Rule 7825.2700, subpart 3, specifies that utilities do not need to file monthly PGAs if the change during the month is less than $0.03 per 1,000,000 Btus (approximately 1 Mcf). This allowance, if exercised by a utility, would cause an over- or under-recovery of gas costs for that month. However, as requested by the Department, utilities file a monthly PGA report even when the change is less than $0.03 per Mcf in order to support the utility's result.

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

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

As discussed above, colder-than-normal weather during FYE14 meant that all of the PGA systems over-recovered demand costs from firm customers. Additionally, all things being equal, commodity costs should have been over recovered. However, prices during the heating season were volatile and higher than expected. Thus, during FYE14, all of the PGA systems under-recovered commodity costs from firm and interruptible customers.

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

A. GREATER MINNESOTA GAS, INC.

1. Recovery of Gas Costs and True-up Calculations

On August 28, 2014, Greater Minnesota submitted its 2014 *Annual Automatic Adjustment Report* in Docket No. G999/AA-14-580 and its *Annual True-up Report* in G022/AA-14-728. GMG included in its reports the information required by Minnesota Rule 7825.2810. The Department concludes that GMG's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE14 reporting period, GMG reported that it under-recovered its total gas costs by $17,377, or approximately 0.27 percent, for a cumulative under-recovery of 0.43 percent.[27] By customer class, Greater Minnesota reported under-recoveries for the current reporting period as follows:

FYE14 Percent Over-Recovery/(Under-Recovery) by Class[28]
(as filed on August 28, 2014 by Greater Minnesota)

Firm	(0.54)
Agricultural - Interruptible	2.54
General – Interruptible	2.73
Total System	(0.27)

Using the sales volumes forecasted by Greater Minnesota for the FYE15 period results in the following true-up factors by customer class:

True-Up Factors per Mcf by Class
(as filed on August 28, 2014 by Greater Minnesota)

Firm	$0.0364
Agricultural - Interruptible	$(0.0973)
General - Interruptible	$(0.0319)

The Department's analysis of Greater Minnesota's gas costs shows that Greater Minnesota's under-recovery was primarily due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Greater Minnesota over-recovered its demand costs by $115,403, or approximately 18.46 percent. The demand-cost over recovery includes capacity-release revenue of $34,105. Without this revenue, there was an over recovery of demand costs of $81,298 or approximately 13.00 percent. In its *2014 Annual Automatic Adjustment Report*, GMG stated that the over-recovery was due to customer growth.[29]

The Department compared GMG's FYE13 to FYE14 true-up sales. GMG's actual FYE14 sales were 1,030,069 Mcf[30] which was 477,384 or 86 percent (477,384/552,685) higher than its FYE13 sales of 552,685 Mcf.[31] The over-recovery would more than likely be attributed to the colder weather during the heating season and new customers. Based on this analysis, the Department concludes that Greater Minnesota's over-recovery of demand costs appears to be reasonable.

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27 This percent represents the cumulative under-recovery of $27,653, which is the basis for GMG's FYE14 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Greater Minnesota's true-up filing, Docket No. G022/AA-14-728.

28 A supporting spreadsheet with detailed calculations is contained in Department Attachment G5.

29 GMG's *Annual Automatic Adjustment Report,* page 4.

30 GMG's *Annual True up Report*, Attachment C, page 1.

31 DOC's FYE13 AAA Report, Attachment G16, Col. (2).

2. Commodity Costs – Greater Minnesota under-recovered its current commodity costs by $132,780, or approximately 2.32 percent. GMG stated that the commodity recovery rate component is based on estimated purchases prior to the beginning of the month, and to the extent estimated volumes and prices vary from actual purchases, a monthly over- or under-recovery will occur.[32]

The Department compared GMG's FYE14 estimated commodity rates to the actual commodity rates. Even though the Department would have expected an over recovery due to colder than normal weather, GMG under estimated its PGA commodity rates in December, January, and February when volumes and costs were the highest. Thus, GMG under-recovered its commodity costs. The Department concludes that GMG's under-recovery of commodity costs appears to be reasonable.

Based on its review, the Department recommends that the Commission accept GMG's FYE14 true-up.

2. Compliance and/or Supplemental Reporting Requirements

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

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

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

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

> 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

32 GMG's *Annual Automatic Adjustment Report,* page 4.

> number of retail GMG customers, and (3) the volume of gas sold to each group of customers.

GMG provided the required information in its filing.[33] The Department concludes that GMG is in compliance with the filing requirements in Docket No. G022/M-11-804.

Docket No. G999/AA-12-756. In this Docket, the Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-Up Proposals, and Setting Further Requirements* required GMG to supplement its tariff to incorporate the terms of its Agricultural-Interruptible Gas Service Agreement. GMG's response to Department Information Request No. 26 stated:

> GMG modified Section 4.1 of its tariff, its Main Extension Policy, to provide that "A gas service agreement specifying minimum use may be used to assure economic feasibility based on projected annual gross margin." GMG also incorporated a model Minimum Use Agreement into Section 7 of its tariff, the Customer Forms and Notices, a copy of which is attached hereto.

The Department concludes that GMG complied with the Commission's Order to supplement its tariff.

Additionally, the *Order* required all regulated gas utilities to prospectively recover balancing service costs (System Management Service (SMS) or Load Management Service (LMS)) and credit the utility's analogous penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that could reasonably be implemented. On its Attachment A of its true-up filing, Greater Minnesota indicated that GMG had implemented this in its December 2013 PGA. The Department concludes that Greater Minnesota complied with the requirement.

3. Summary and Recommendations

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

- accept GMG's FYE14 true-up, Docket No. G001/AA-14-728; and
- allow GMG to implement its true-up, as shown in DOC Attachment G5 of the *AAA Report*.

B. GREAT PLAINS NATURAL GAS COMPANY

1. Recovery of Gas Costs and True-Up Calculations

On August 29, 2014, Great Plains submitted its 2014 *Annual Report of Automatic*

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

Adjustment of Gas Charges in Docket No. G999/AA-14-580 and its *Annual True-Up Report* in Docket No. G004/AA-14-749, 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 FYE14 reporting period, Great Plains North under-recovered its total gas costs by $1,678,152, or approximately 12.09 percent, for a cumulative under-recovery of total gas costs of approximately 11.48 percent.[34]

The PGA system for Great Plains South under-recovered total gas cost by $2,091,994, or approximately 13.57 percent, for a cumulative under-recovery of 12.97 percent.[35] The Department's analysis indicates that, by district and customer class, Great Plains' over/under-recoveries for the current reporting period as follows:[36]

FYE14 Percent Over-Recovery/(Under-Recovery)[37]
(as filed August 29, 2014 by Great Plains)

Class[38]	North District	South District
Firm	(12.89)	(13.94)
Small Volume Interruptible	-	(14.04)
Large Volume Interruptible	-	(11.81)
Interruptible	(9.74)	-
Total System	(12.09)	(13.57)

Using the sales volumes forecasted by Great Plains for the FYE15 period results in the following true-up factors by district and by customer class:

34 The figure of 11.48 percent represents the cumulative under-recovery of $1,592,741, which is the basis for the August 29, 2014 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Great Plains' true-up filing, Docket No. G004/AA-14-749.

35 The figure of 12.97 percent represents the cumulative under-recovery of $1,999,088, which is the basis for the August 29, 2014 true-up adjustment. For a detailed breakdown of the true-up calculations, please see Great Plains' true-up filing, Docket No. G004/AA-14-749.

36 The term "North District" refers 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" refers 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.

37 Supporting spreadsheets with detailed calculations are contained in DOC Attachments G6a and G6b.

38 Regarding interruptible classes, Great Plains has Small Volume Interruptible (SVI) and Large Volume Interruptible (LVI) classes in the South District, and has a single Interruptible class in the North District.

True-Up Factors per Mcf
(as filed on August 29, 2014 by Great Plains)

Class	North District	South District
Firm	$1.0923	$0.9546
Small Volume Interruptible	-	$1.0607
Large Volume Interruptible	-	$0.4775
Interruptible	$0.7344	-

a. North District

The Department's analysis shows that Great Plains under-recovered its total gas costs for the North District by $1,678,152, or approximately 12.09 percent, during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Great Plains over-recovered its demand costs for the North District by $317,687, or approximately 19.34 percent, during the reporting period. The demand-cost over recovery includes interruptible curtailment revenue of $5,781. The over recovery also includes Great Plains' adjustments which increased the over-recovery by $80,537. Without this revenue and Great Plains' adjustments, there was an over recovery of demand costs of $231,369 or approximately 14.09 percent. Great Plains stated that the over-recovery of demand costs for the North District was due to the following reasons: [39]

    - Weather was 11.16 percent colder than normal for the twelve months ending June 30, 2014; and

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

As discussed above in Section I, colder-than-normal weather resulted in a marked increase in natural gas sales during the current reporting period. Based on its analysis, the Department concludes that Great Plains' over-recovery of demand costs in the North District appears to be reasonable.

As stated above, Great Plains' adjustments increased the over-recovery by $80,537. The Department requested that Great Plains explain its adjustments. Great Plains responded that the first item was an adjustment of $2,773 related to the disallowance of cost recovery of $2,578.38 plus interest at the prime rate under Docket No. G999/AA-11-793. This issue is discussed below under Great Plains' *Compliance and/or Supplemental Reporting Requirements*.

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[39] Great Plains' *Annual Automatic Adjustment Report,* page 3.

According to Great Plains, the second item of $77,764 was a decrease related to Viking Transmission Co.'s (Viking) FT-A (Zone 1-1; Zone 1-2) service:

> …a reclassification of demand costs recorded in the balancing account from the North District to the South District. However, upon further review, the adjustment shown for the North District included ($59,424) that had been properly reflected in the prior year's activity which was included in the GCR approved in Docket No. G004/AA-13-800 [Great Plains' prior true up docket].

Thus, Great Plains concluded that demand costs should not have been reduced by the $59,424 amount. Great Plains provided to the Department revised true-up schedules and stated "The result in the ending balance being understated by $59,424 and this correction results in an increase [from $1.0923 to $1.1452] of $0.0529 per Dk in the annual True-up Report filed for the North District under Docket No. G004/AA-14-749."[40]

The Department notes that the error is 4.62 percent[41] of the corrected adjustment charge or less than the five percent required under Minn. R. 7825.2920, subp. 2 before "errors made in adjustment must be adjusted by check or credits to bills." However, the Department concludes that the current true-up factor for the North District's Firm customers does not reflect the correct gas costs. The Department recommends that the Commission require Great Plains to report the correction to demand costs as a separate line item to the beginning balance of the demand cost of gas in its September 1, 2015 true-up.

2. Commodity Costs – Great Plains' North District under-recovered its commodity costs by $1,995,839, or approximately 16.31 percent. Great Plains stated that the under-recovery was primarily related to:

> …higher volumes purchased during January through March 2014 due to the colder weather. Great Plains' practice is to purchase gas on the first of the month index price to cover the majority of the needs based on normal operating conditions. The remainder of the gas is purchased in the spot market. Great Plains' purchases during the January through March timeframe were increased due to the colder weather and those volumes were generally purchased in the daily spot market which greatly exceeded the estimated spot price used to calculate the cost of gas included in the tariff. Market conditions, including the explosion of a line section of the TransCanada Pipeline in January 2014, colder weather across a large portion of the region and low storage levels, put upward pressure on the spot prices in excess of the amount included as an estimate. Great Plains does not have access to storage facilities in the North District.

40 There was no change to the interruptible class true up factor.

41 4.62% = $0.529/$1.0923

The Department appreciates Great Plains' thorough explanation of the commodity under recovery. Based on this information and the Department's expectations of commodity under recovery for the heating season, the Department concludes that Great Plains' under-recovery of commodity costs for the North District appears to be reasonable.

b. South District

The Department's analysis shows that Great Plains under-recovered its total gas costs for the South District by $2,091,994, or approximately 13.57 percent, during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Great Plains over-recovered demand costs for the South District by $331,942, or approximately 20.89 percent, during the reporting period. The demand-cost over recovery includes interruptible curtailment revenue of $940. The over recovery also includes Great Plains' adjustments which decreased the over-recovery by $51,228. Without this revenue and Great Plains' adjustments, there was an over recovery of demand costs of $382,230 or approximately 24.06 percent. Great Plains stated that its over-recovery of demand costs for the South District was due to the following reasons:[42]

   - The weather was 14.12 percent colder than normal for the twelve months ending June 30, 2014.

   - 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. The colder than normal weather exacerbated the winter over recovery.

As discussed above in Section I, colder-than-normal weather resulted in a marked increase in natural gas sales during the current reporting period. Based on its analysis, the Department concludes that Great Plains' over-recovery of demand costs in the South District appears to be reasonable.

As stated above, Great Plains' adjustments decreased the firm demand over-recovery by $51,228. The Department requested that Great Plains explain the adjustments. Great Plains responded that the first item was an adjustment of $44,271 related to the disallowance of cost recovery of $41,162.14 plus interest at the prime rate under Docket No. G999/AA-11-793.[43] This issue is discussed below under Great Plains South *Compliance and/or Supplemental Reporting Requirements*.

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[42] Great Plains' AAA Report, pages 4-5.

[43] The October 17, 2013 Order denied Great Plains' costs totaling $55,885. The Department's FYE11 AAA Report, page 15, provides the amounts by District and class: North District-Firm $2,578, South District-Firm $41,162 and South District-Interruptible $12,145.

According to Great Plains, the second item of $95,499 was a decrease related to Viking's FT-A (Zone 1-1; Zone 1-2) service:

> …a reclassification of demand costs recorded in the balancing account from the North District to the South District. However, upon further review, the adjustment shown for the South District included $33,126 that had been properly reflected in the prior year's activity which was included in the GCR approved in Docket No. G004/AA-13-800 [Great Plains' prior true up docket].

Thus, Great Plains concluded that demand costs should not have been increased by the $33,126. Great Plains provided to the Department revised true-up schedules and stated "The result in the ending balance being overstated by $33,126 and this correction results in a decrease [from $0.9546 to $0.9324] of $0.0222 per Dk in the annual True-up Report filed for the South District under Docket No. G004/AA-14-749."

Another error was subsequently discovered during the Department's investigation. The Department questioned why the South District's propane peaking facilities credit of $126,404 was the same amount for recovered cost and actual cost. Great Plains responded that the actual costs were in error and should be correct to $102,945 since that was the credit agreed to by Great Plains in its 2004 general rate case Docket No. G004/GR-04-1487.

The Department notes that Great Plains South District's errors are 0.67 percent[44] of the corrected adjustment charge or less than the five percent required under Minn. R. 7825.2920, subp. 2 before "errors made in adjustment must be adjusted by check or credits to bills."

Nonetheless, the Department concludes that the current true-up factor for the South District's Firm customers does not reflect the correct gas costs. The Department recommends that the Commission require Great Plains to describe and report each of the FYE14 corrections as a separate line item to the beginning balance of the demand cost of gas in its September 1, 2015 true-up.

2. Commodity Costs – Great Plains' South District under-recovered its commodity costs by $2,423,936, or approximately 17.53 percent.[45] Great Plains stated that the under-recovery was primarily related to:

> …higher volumes purchased during January through March 2014 due to the colder weather. Great Plains' practice is to purchase gas on the first of the month index price to cover the majority of the needs based on normal operating conditions. The remainder of the gas is purchased in the spot market. Great Plains' purchases during the January through March

44 0.67% = $0.0064/$0.9482.

45 On page 4 of its AAA Report Great Plains incorrectly stated that the commodity components were under recovered by $2,339,432 including adjustments.

> timeframe were increased due to the colder weather and those volumes were generally purchased in the daily spot market which greatly exceeded the estimated spot price used to calculate the cost of gas included in the tariff. Market conditions, including the explosion of a line section of the TransCanada Pipeline in January 2014, colder weather across a large portion of the region and low storage levels, put upward pressure on the spot prices in excess of the amount included as an estimate. Great Plains does have limited storage capability in the South District and did use the full extent of the available storage, somewhat mitigating the necessary purchases in the spot market.

The Department appreciates Great Plains' thorough explanation of the commodity under recovery. Based on this information and the Department's expectations of commodity under recovery for the heating season, the Department concludes that Great Plains' under-recovery of commodity costs for the South District appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G999/AA-11-793. The Commission's October 17, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-Up Proposals, Clarifying Requirements, and Setting Further Requirements* denied recovery from ratepayers of the $55,885 included in its beginning cumulative true-up balance and required Great Plains (North and South) to record on its books a separate line item reducing its true-up costs by $55,885 plus interest calculated at the prime rate. The Department's March 1, 2012 AAA Report, page 15, provides the amounts by District and class: North District-Firm $2,578, South District-Firm $41,162 and South District-Small Volume Interruptible $12,145. Great Plains correctly calculated the interest[46] on the disallowance by month from September 1, 2011 through November 2013. In addition to reducing firm demand costs by the disallowances, Great Plains decreased the commodity costs charged to Small Volume Interruptible customers. The Department concludes that Great Plains complied with the Commission's Order in Docket No. G999/AA-11-793.

Docket No. G999/AA-12-756. The Commission required all regulated gas utilities to prospectively recover balancing service costs SMS or LMS and credit the utility's analogous penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that could reasonably be implemented. In December 2014, the Department asked Great Plains if it complied with the Order. Great Plains said that it would make the necessary adjustments in its January 2015 PGA filings.[47] Subsequently, the Department learned that Great Plains has been allocating LMS and SMS costs between firm and interruptible

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[46] Great Plains used interest at the prime annual rate of 3.25 percent.

[47] In its cover letters to the PGAs in Docket Nos. G004/AA-15-22 and G004/AA-15-23, Great Plains stated that it has "moved" the recovery of its LMS (Great Plains North) and SMS (Great Plains South) charges from the demand portion of the PGA to the commodity portion.

customers since 2010.[48] Thus, moving the balancing costs to commodity was solely a matter of presentation.

Based on its review, the Department recommends that the Commission accept Great Plains' FYE14 true-up.

3. Summary and Recommendations

The Department concludes that Great Plains' FYE14 annual automatic adjustment report is complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept Great Plains' FYE14 true-ups, Docket No. G004/AA-14-749;
- allow Great Plains to implement its true-ups, as shown in DOC Attachments G6a and G6b of the *AAA Report*; and
- describe and report each of the FYE14 corrections as a separate line item to the beginning balance of the demand cost of gas in its September 1, 2015 true-up.

C. INTERSTATE POWER AND LIGHT COMPANY-GAS UTILITY

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

1. Recovery of Gas Costs and True-up Calculations

Interstate Gas submitted its *2014 Gas Annual Automatic Adjustment Report* on August 29, 2014 in Docket No. G001/AA-14-742 in compliance with Minnesota Rule 7825.2810. The Department concludes that Interstate Gas' filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

For the FYE14 reporting period, Interstate Gas reported that it over-recovered its total gas costs by $599,448, or approximately 5.92 percent, for a cumulative over-recovery of approximately 5.63 percent.[49] By customer class, Interstate Gas reported over/under-recoveries for the current reporting period as follows:

48 See Order dated September 30, 2010 in Docket No. G004/M-07-1401.

49 The figure of 5.63 percent represents the accumulated over-recovery of $570,018, and is the actual amount on which the FYE14 true-up adjustment calculations are based. For a detailed breakdown of the true-up calculation, please see Interstate Gas' true-up filing, Docket No. G001/AA-14-742.

FYE14 Percent Over-Recovery/(Under-Recovery)[50]
(As filed on August 29, 2014 by Interstate Gas)

Firm	7.28
Small Interruptible	(0.58)
Large Interruptible	0.00
Total System	5.92

Using the sales volume forecasted by Interstate Gas for the FYE15 true-up period results in the following true-up factors by customer class:

True-Up Factors per Mcf
(as filed on August 29, 2014 by Interstate Gas)

Firm	$(0.4702)
Small Interruptible	$0.0403
Large Interruptible	$0.0000

The Department's analysis shows that Interstate Gas over-recovered its total gas costs by $599,448, or approximately 5.92 percent, during the reporting period. This over-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – Interstate Gas over-recovered its Assigned Demand[51] costs by $531,006, or approximately 39.84 percent. The demand-cost over recovery also includes interruptible penalty revenue of $37,118 and capacity-release revenue of $25,538. Without these revenues, there was an over recovery of demand costs of $468,349 or approximately 35.13 percent. Interstate Gas stated that the over collection was mainly the result of higher actual sales volumes than had been forecasted in the monthly PGA factor calculations due to extremely cold winter which resulted in higher revenue collections from customers.[52]

During its investigation, the Department questioned why the total incurred costs for both rate classes on Interstate Gas' Exhibit B, page 1 totaling $10,119,966.42 did not agree with its Exhibit M, page 25 totaling $10,157,313.62. Interstate Gas responded that it inadvertently did not include the Interruptible penalty revenue of $37,118 and prior period adjustment credits of $230 for July and August 2013 in Exhibit M (Monthly Revenue True Up Information) totals but did on Exhibit B (Automatic Adjustment Charges Automatic Adjustment Under/(Over) Collection). On October 30, 2014, Interstate Gas filed revised schedules showing the correct monthly information. The Department concludes that these monthly presentation errors did not affect the true-up factors.

As discussed above in Section I, colder-than-normal weather resulted in a marked increase in natural gas sales during the current reporting period. Based on its analysis, the Department concludes that Interstate Gas' over-recovery of Assigned Demand costs appears to be reasonable.

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50 A supporting spreadsheet with detailed calculations is contained in Department Attachment G7.

51 "Assigned Demand" costs are charged only to firm customers.

52 See Exhibit I of Interstate Gas' AAA Report filed in Docket No. G999/AA-14-742.

2. Allocated Demand – Interstate Gas over-recovered its total Allocated Demand[53] costs by $75,444 ($60,135 to firm + $15,309 to interruptible) or approximately 22.81 percent. Interstate Gas stated that “[t]he Allocated Demand costs for the period July 2013 through June 2014 were all over-collected because an extremely cold winter caused actual sales to be higher than the forecasted sales used in calculating the PGA factor.”[54]

Based on its analysis, the Department concludes that Interstate Gas’ over-recovery of Allocated Demand costs appears to be reasonable.

3. Commodity Costs–Interstate Gas under-recovered its commodity costs by $7,001 ($18,377 to firm - $25,378 to interruptible), or approximately 0.08 percent.

Based on its analysis, the Department concludes that Interstate Gas’ under-recovery of commodity costs appears to be reasonable.

Thus, the Department recommends that the Commission accept Interstate Gas’ FYE14 true-up.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G999/AA-12-756. The Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-up Proposals, and Setting Further Requirements* (Docket No. 12-756) required all regulated gas utilities to prospectively recover balancing service costs SMS or LMS and credit the utility's analogous penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that could reasonably be implemented.[55]

Interstate Gas’ non-compliance to the Order in Docket No. 12-756 was discussed in Commission Staff’s January 29, 2015 Briefing Papers in Interstate Gas’ 2014 demand entitlement request, Docket No. G001/M-14-560 (Docket No. 14-560). In its February 6 *Order* in Docket No. 14-560, the Commission accepted IPL’s proposal to correct the SMS cost allocation in its 2015 true-up filing and granted IPL a variance to the Natural Gas Utility Billing Errors Rule, Minn. R. 7820.4000. The Department expects to review the adjustment in the FYE15 true-up filing.

3. Summary and Recommendations

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

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53 “Allocated Demand” is shown by class in Interstate Gas’ AAA Report. It reflects the portions of demand costs allocated to each class.

54 Interstate Gas’ AAA Report, Exh. L.

55 Interstate Gas implemented the allocation of its SMS costs among their firm and interruptible customers in its January 2015 PGA, Docket No. G001/AA-14-1072.

- accept Interstate Gas' true-up filing in Docket No. G001/AA-14-742; and
- allow Interstate Gas to implement its true-up, as shown in Department Attachment G7 of the *AAA Report*.

D. MINNESOTA ENERGY RESOURCES CORPORATION (MERC)

1. Recovery of Gas Costs and True-Up Calculations

The FYE14 was the first year of truing up the costs of the two PGA systems: MERC-NNG and MERC-Consolidated.[56] In MERC's FYE13 true-up filings,[57] the costs of the four PGA systems were presented for the year and the true-up amounts were allocated between the two new systems on June 30, 2013.

On September 2, 2014, MERC-NNG submitted its 2014 *Annual Automatic Adjustment Report* in Docket No. G011/AA-14-755 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 FYE14 reporting period, MERC-NNG under-recovered its total gas costs by $12,346,729, or approximately 6.45 percent, for a cumulative under-recovery of total gas costs of approximately 6.12 percent.[58]

The PGA system for MERC-Consolidated under-recovered total gas cost by $3,722,696, or approximately 9.25 percent, for a cumulative under-recovery of 11.65 percent.[59]

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

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56 On December 21, 2012, in Docket No. G007,011/GR-10-977, the Commission approved the consolidation of MERC's four PGA systems into two PGA systems. Additionally, on December 21, 2012 in Docket No. G007, 011/MR-12-1028, the Commission approved the new base cost of gas rates for the two new PGA systems beginning with bills rendered on July 1, 2013. The two new PGA systems were named MERC-NNG (consisting of MERC-PNG's and MERC-NMU's Northern PGA system customers) and MERC-Consolidated (consisting of MERC-PNG's and MERC-NMU's Great Lakes, Viking, Centra PGA system customers).

57 Docket Nos. G011/AA-13-798 (MERC-PNG) and G007/AA-13-799 (MERC-NMU).

58 The figure of 6.12 percent represents the cumulative under-recovery of $11,714,073, which is the basis for the September 2, 2014 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-NNG's true-up filing, Docket No. G011/AA-14-755.

59 The figure of 11.65 percent represents the cumulative under-recovery of $4,689,373, which is the basis for the September 2, 2014 true-up adjustment. For a detailed breakdown of the true-up calculations, please see MERC-Consolidated's true-up filing, Docket No. G011/AA-14-754.

FYE14 Percent Over-Recovery/(Under-Recovery)
by System and Class[60]
(as filed on September 2, 2014 by MERC)

Class[61]	NNG	Consolidated
GS	(6.10)	(9.49)
SVJ/LVJ/SLVJ Demand	0.00	0.00
SVI/SVJ/LVI/LVJ/SLVI Commodity	(10.81)	(7.77)
Total System	(6.45)	(9.25)

Using the sales volumes forecasted by MERC for the year ending August 31, 2015 results in the following true-up factors by system and class:

True-Up Factors per Mcf
by System and Customer Class
(as filed on September 2, 2014 by MERC)

Class	NNG	Consolidated
GS	$0.4714	$0.8726
SVJ/LVJ/SLVJ Demand	$(0.0009)	$(0.0049)
SVI/SVJ/LVI/LVJ/SLVI Commodity	$0.5275	$0.5703

a. MERC-NNG

The Department's analysis shows that MERC under-recovered its total gas costs on its NNG System by $12,346,729, or approximately 6.45 percent, during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – MERC over-recovered its demand costs for the MERC-NNG system by $8,917,995, or approximately 24.46 percent. The demand-cost over-recovery also includes capacity-release revenue of $1,374,191 and curtailment penalty revenue of $570,860.[62] Without these revenues, there was an over-recovery of demand costs of $6,972,944 or approximately 19.13 percent. In its filing, MERC-NNG stated that the "over collection of demand cost was predominantly caused by the actual sales being greater than projected sales."[63]

[60] Supporting spreadsheets with detailed calculations are contained in DOC Attachments G8 and G9.

[61] MERC has the following classes:
- General Service (GS);
- Small Volume Interruptible (SVI);
- Large Volume Interruptible (LVI);
- Super Large Volume Interruptible (SLVI);
- Small Volume Joint (SVJ);
- Large Volume Joint (LVJ); and
- Super Large Volume Joint (SLVJ).

[62] MERC-NNG's AAA Report, Schedule D.3, page 6.

[63] See MERC-NNG's AAA Report, page 3.

As discussed above in Section I, colder-than-normal weather resulted in a marked increase in natural gas sales during the current reporting period. Based on its analysis, the Department concludes that MERC-NNG's over-recovery of demand costs appears to be reasonable.

2. Commodity Costs –MERC-NNG under-recovered commodity costs by $21,264,724, or approximately 13.72 percent. In its filing, MERC-NNG stated that the "under collection was caused by the difference in projected monthly gas costs compared to actual gas costs."[64]

The Department compared MERC-NNG's FYE14 estimated commodity rates to the actual commodity rates. Even though the Department would have expected an over recovery due to colder than normal weather, MERC-NNG under estimated its PGA commodity rates in December, January, February, and March when volumes and costs were the highest. Thus, MERC-NNG under-recovered its commodity costs. The Department concludes that MERC-NNG's under-recovery of commodity costs appears to be reasonable.

b. MERC-Consolidated

The Department's analysis shows that MERC under-recovered its total gas costs for the Consolidated System by $3,722,696, or approximately 9.25 percent, during the reporting period. This under-recovery was due to the following demand-cost and commodity-cost factors:

1. Demand Costs – MERC over-recovered its demand costs for the MERC-Consolidated system by $1,060,752, or approximately 27.79 percent. The demand-cost over-recovery also includes capacity-release revenue of $37,037[65] and curtailment penalty revenue of $335,845. Without these revenues, there was an over-recovery of demand costs of $687,870, or approximately 18.02 percent. In its filing, MERC- Consolidated stated that the "over collection of demand cost was predominantly caused by the actual sales being greater than projected sales."[66]

As discussed above in Section I, colder-than-normal weather resulted in a marked increase in natural gas sales during the current reporting period. Based on its analysis, the Department concludes that MERC- Consolidated's over-recovery of demand costs appears to be reasonable.

2. Commodity Costs –MERC- Consolidated under-recovered commodity costs by $4,783,448, or approximately 13.13 percent. In its filing, MERC- Consolidated stated that the "under collection was caused by the difference in projected monthly gas costs compared to actual gas costs."[67]

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64 MERC-NNG's AAA Report, page 3.

65 MERC-Consolidated's AAA Report, Schedule D3, page 6.

66 See MERC-NNG's AAA Report, page 3.

67 MERC-NNG's AAA Report, page 3.

The Department compared MERC-Consolidated's FYE14 estimated commodity rates to the actual commodity rates. Even though the Department would have expected an over recovery due to colder than normal weather, MERC-Consolidated under estimated its PGA commodity rates in the five winter months and especially in January through March when volumes and costs were the highest. Thus, MERC-NNG under-recovered its commodity costs. The Department concludes that MERC- Consolidated's under-recovery of commodity costs appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G999/AA-13-600. Regarding allocation errors between MERC-NNG and MERC-Consolidated, in its April 11, 2014 *Order* the Commission required MERC to:

- adjust the September 1, 2014 true-up balance for its MERC-Consolidated classes that were undercharged due to the allocation error by the Company;
- adjust the September 1, 2014 true-up balance for MERC-NNG's classes that were overcharged due to the allocation error;
- pay interest to the MERC-NNG's classes beginning September 1, 2013 computed at the prime rate on the total amount of the over-collection error $664,423 and provide the interest calculation detail in the Company's September 1, 2014 true-up report; and
- report the allocation adjustments and interest as separate line items to the beginning balance of the commodity cost of gas in its September 1, 2014 true-up.

MERC included information regarding these *Order* requirements in its AAA Reports, page 5 for MERC-NNG and page 6 for MERC-Consolidated, and in its Schedule K. The Department notes that MERC paid to MERC-NNG's ratepayers $23,369 of interest at the monthly prime rate of 3.25 percent. The Department concludes that MERC complied with the *Order*.

Docket Nos. G007,011/M-06-1358, G007,011/M-09-262, G007,011/M-11-296, and G007,011/M-13-207. In these dockets, the Commission allowed MERC to recover the costs associated with using financial instruments in securing natural gas supplies through the PGA. The *Orders* in these dockets require MERC to report and provide in future AAA filings data on the relative benefits of price hedging contracts, including the average cost per dekatherm for natural gas purchased using financial instruments compared to the relevant monthly and daily spot index prices, together with the following information:

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

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

MERC included information regarding these *Order* requirements in its AAA Reports, pages 6 and 7, and in Schedules L and O. The Department discusses MERC's hedging costs in Section III, part O, of this *Report*.

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

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

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

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

MERC included information regarding these *Order* requirements in its AAA Reports, pages 6-12, and in Schedule P. The Department discusses MERC's hedging costs in Section III, part O, of this *Report*.

Docket No. G999/AA-12-756. The Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-up Proposals, and Setting Further Requirements* (Docket No. 12-756) required all regulated gas utilities to prospectively recover balancing service costs SMS or LMS and credit the utility's analogous penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that could reasonably be implemented. MERC complied with the Order by moving the balancing costs to commodity in its November 1, 2013 PGAs, Docket Nos. G011/AA-13-1013 and G011/AA-13-1014.

Based on its review, the Department recommends that the Commission accept MERC's FYE14 true-ups.

3. Summary and Recommendations

The Department concludes that MERC's FYE14 annual automatic adjustment reports are complete with respect to Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept MERC- NNG's true-up filing in Docket No. G011/AA-14-755;
- allow MERC- NNG to implement its true-up, as shown in Department Attachment G8 of the *AAA Report*;
- accept MERC- Consolidated's true-up filing in Docket No. G011/AA-14-754; and
- allow MERC- Consolidated to implement its true-up, as shown in Department Attachment G9 of the *AAA Report*.

E. CENTERPOINT ENERGY

1. Recovery of Gas Costs and True-Up Calculations

On September 2, 2014, CenterPoint Energy submitted its 2014 Annual Automatic Adjustment Report in Docket No. G999/AA-14-580 and its Annual True-Up Report in Docket No. G008/AA-14-752 in compliance with Minnesota Rule 7825.2810. The Department concludes that CenterPoint Energy's filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

According to CenterPoint Energy's true-up filing, CenterPoint Energy under-recovered gas costs by $62,089,561, or approximately 6.88 percent, with a cumulative under-recovery of approximately 5.62 percent[68] of its actual gas cost incurred. By customer class, CenterPoint Energy reported under-recoveries for the current reporting period as follows:

FYE14 Percent Over-Recovery/ (Under-Recovery) [69]
(As filed on September 2, 2014 by CenterPoint Energy)

Class	
Small Volume Firm	(7.00)
Large General Service	0.00
Small Volume Dual Fuel	(5.48)
Large Volume Dual Fuel	(7.32)
Total System	(5.62)

Using sales volumes forecasted by CenterPoint Energy for year 2015 results in the following proposed true-up factors by class.[70]

68 The figure of 5.62 percent represents the cumulative under-recovery of $50,774,666, which is the basis for the FYE14 true-up factors. For a detailed breakdown of the true-up calculation, please see CenterPoint Energy's true-up filing, Docket No. G008/AA-14-752.

69 A supporting spreadsheet with detailed calculations is contained in Department Attachment G10.

70 See CenterPoint Energy's true up, page 12 for the 2015 monthly sales estimate.

True-Up Factors per Dekatherm (dth)
(As filed on September 2, 2014 by CenterPoint Energy)

Class	Factor
Small Volume Firm	
Residential	$0.4083
Commercial A & Com/Ind. B	$0.4083
Commercial/Industrial C	$0.4083
Large General Service	$0.0163
Small Volume Dual Fuel	$0.3155
Large Volume Dual Fuel	$0.4131

The Inverted Block Rate (IBR) pilot program for the Residential, Commercial A, and Commercial/Industrial B classes was effective July 1, 2010 as ordered in Docket No. G008/GR-08-1075. On October 4, 2011, the Commission ordered the suspension of the IBR pilot effective October 14, 2011, and on August 10, 2012 ordered CenterPoint to terminate the inverted block rate structure. The remaining balance to true up at FYE14 was an over recovery of $25,594.[71]

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

1. Demand Costs (including propane costs for peak-shaving) – CenterPoint Energy over-recovered demand costs by $7,344,058 or approximately 10.00 percent including off-system sales revenue of $6,589,090 and curtailment revenue of $916,066. Without these revenues, there was an under recovery of demand costs of $161,098 or approximately 0.22 percent. In its filing,[72] CenterPoint Energy stated that the demand-cost under-recovery of 0.22 percent resulted from weather that was about 18 percent colder than normal and sales that were 18,604,217 dth or 18.4 percent more than the weather-normalized sales of 100,990,000 dth used to calculate the demand recovery factor. According to CenterPoint Energy, adjustments to demand from the "demand smoothing" factor brought the demand cost recovery much closer to the demand costs incurred.

As shown in the demand smoothing compliance table below, CenterPoint indicated that its over-recovery without the program would have been 15.4 percent rather than 0.22 percent under-recovery reported above (rounded to 0.2 percent in the company's table below). Further, in most years CenterPoint Energy's demand smoothing program has resulted in over- or under-recoveries that are closer to zero. The Department concludes that CenterPoint Energy's demand cost under-recovery is reasonable.

[71] CenterPoint Energy's true up, pages 9 and 11 and AAA Report, page 18. CenterPoint Energy stated that "CPE will discontinue the separate IBR tracking effective September 1, 2014 as allowed in point 7 of the order dated August 10, 2012 in Docket G-008/GR-08-1075."

[72] See CenterPoint Energy's AAA Report, page 18.

2. Commodity Costs – CenterPoint Energy under-recovered commodity costs by $61,928,463, or approximately 7.47 percent. In regard to the under-recovery, CenterPoint Energy stated:

> In planning for the 2013-2014 season, leading industry forecasts indicated stable prices and colder than normal weather (and sustained cold) was not anticipated, storage was full and reserves/production were high. CenterPoint Energy developed plans prior to the heating season to reliably meet needs based on expected loads and later adjust to actual weather related requirements. Given historical experience, CenterPoint Energy contracted the majority of its swing supplies priced at the daily market price when called upon.
>
> CenterPoint Energy experienced significant variation in daily load, particularly in January and February, requiring the use of its contracted swing gas. In 2013-2014 there was a confluence of events that caused significant market disruptions, resulting high daily market prices. Events included frequent and sustained cold spells both in the Midwest and across the country, pipeline operational issues resulting in operational flow orders, and a pipeline explosion on TransCanada pipeline that caused major market reactions at the Ventura gas exchange point. In addition, other market forces, such as increased natural gas demand for electric generation, disruptions in gas production as a result of well freeze-off, Demarc and Emerson supply points being fully utilized so additional supply had to come from other sources, and significant seasonal draw-down of storage kept pressure on the market to keep daily prices higher than anticipated.
>
> Due to the cold weather, CenterPoint Energy purchased more swing gas supplies than if the weather had been "normal" and those supplies were priced at daily market prices; which were more volatile than in prior years. The increase in swing as volumes and price volatility both drove up the average cost compared to the planned purchases used in setting the monthly PGA rate. CPE used its storage supplies and hedged gas purchases to moderate the volatile market prices. Additionally, CPE was able to offset some of the under recovery with off-system sales.[73]

The Department appreciates CenterPoint Energy's thorough explanation of the commodity under recovery. Based on this information and the Department's expectations of commodity under recovery for the heating season, the Department concludes that CenterPoint Energy's under recovery of commodity costs appears to be reasonable.

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73 See CenterPoint Energy's AAA Report, pages 17-18.

2. *Compliance and/or Supplemental Reporting Requirements*

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

In Exhibits 3 and 4 of its AAA Report, CenterPoint Energy included the required information.[76] Since the inception of this program, the demand-cost recovery results have been as follows:[77]

	With Program Recovery		Without Program	
Year	Over/(Under)[78]	Percent	Over/(Under)	Percent
FYE01	$(1,859,854)	(1.6)	$6,060,569	5.2
FYE02	$2,140,282	2.1	($9,835,529)	(9.6)
FYE03	$195,409	0.2	$7,784,072	7.9
FYE04	$(1,167,912)	1.0	$(1,197,490)	(1.0)
FYE05	$(934,612)	(0.8)	$(1,530,385)	(1.3)
FYE06	$(406,837)	(0.4)	$(12,087,038)	(10.4)
FYE07	$7,519,994	7.0	$(286,342)	(0.3)
FYE08	$2,511,582	2.9	$1,322,689	1.5
FYE09	$3,098,947	4.7	$4,489,569	6.8
FYE10	$(5,149,579)	(6.6)	$(7,327,401)	(9.4)
FYE11	$1,164,918	1.5	$3,903,613	5.1
FYE12	$(4,482,056)	(6.0)	$(11,272,158)	(15.1)
FYE13	$7,310,268	10.0	$5,025,956	6.9
FYE14	$(149,278)[79]	(0.2)	$11,295,219	15.4

74 CenterPoint Energy's Demand Adjustment was not charged to its Viking area customers until consolidation of the PGAs in 2005.

75 Docket No. G008/M-13-728.

76 See CenterPoint Energy's AAA Report, page 19 for a discussion.

77 The data in this exhibit does not include "No Surprise Bill©" (NSB) customer data starting with November 2001 until termination of the program in December 2007. NSB customer demand costs were recovered on weather-normalized sales and a fixed recovery rate.

78 For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar-month data rather than billing-month data).

79 Includes demand-related revenue.

As shown above, except for FYE07, FYE08, and FYE13, the program has provided a better match of costs and recoveries within the true-up year than would have been the case without this program.[80] In FYE14 actual under recovery of $149,278 outperformed the hypothetical over recovery of $11,295,219.

CenterPoint Energy also provided Exhibit 4 to comply with the reporting requirement that it continue to report the results of the actual monthly demand adjustment compared to a hypothetical monthly demand-cost recovery rate that reflects a one-month lag. Under CenterPoint Energy's "without lag adjustment," the monthly sales amount for January 1 would include actual sales through November and estimated sales for December.

Year	With One-Month Lag Adjustment Over/(Under) Recovery	Without Lag Adjustment[81] Over/(Under) Recovery
FYE08	$939,032	$1,322,689
FYE09	$3,873,820	$3,098,947
FYE10	$(4,394,252)	$(5,149,579)
FYE11	$2,306,874	$1,164,918
FYE12	$(4,568,677)	$(4,482,056)
FYE13	$3,954,396	$5,025,955
FYE14	$688,175	$(149,278)

In FYE14, actual under recovery of $149,278 outperformed the hypothetical over recovery of $688,175. The Department concludes that CenterPoint Energy complied with the filing requirements in the Commission's *Order* in Docket No. G008/M-13-728.

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

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

- include information on the call options contracts and swing contracts with reservation fees used during the year and the price paid for natural gas through each of these types of contractual arrangements; and

80 Regarding FYE07, the Commission modified the pilot program in its December 24, 2007 *Order* to account for capacity-release credits due to the large over recovery in FYE07. The over recovery was larger due to adding capacity-release credits for the first time starting in January 2008. For FYE08, the demand cost adjustment was not in place for three months (October through December of 2007) since CenterPoint Energy's request for a continued variance in Docket No. G008/M-07-1063 was not approved until December 24, 2007. Thus, the results of the FYE08 demand cost adjustment program may not be indicative of what the results would have been over the full eight months of the program.

81 This column contains the hypothetical amounts.

- 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.

CenterPoint Energy complied by including a comparison of the cost of swing gas with the costs for natural gas in the spot market in its Exhibit 6A and B of its AAA Report for Docket No. 01-540. CenterPoint Energy's Exhibit 7 lists hedge volumes and Exhibit 8 estimates impacts on customer bills as a result of using hedging products in its supply portfolio during the true-up period.

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

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

CenterPoint Energy complied by including this information in its Exhibit 7 of its AAA Report. The Department concludes that CenterPoint Energy complied with the filing requirements in Docket Nos. 01-540 and 08-777. The Department discusses CenterPoint Energy's hedging costs in Section III, part O, of this *Report*.

<u>Docket No. G999/AA-08-1011</u>. As noted above, the Commission directed Xcel Gas, CenterPoint Energy, and MERC to provide the Department with information about their hedging programs, beginning in fiscal-year 2010. CenterPoint Energy provided this information in pages 19-21, as well as in Exhibit 8 of its Annual Report. The Department concludes that CenterPoint Energy complied with the filing requirements in Docket No. G999/AA-08-1011. The Department discusses CenterPoint Energy's hedging costs in Section III, part O, of this *Report*.

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

CenterPoint Energy included the required information on pages 10 and 14 of its annual True-Up filing. Upon review of this information, the Department concludes that CenterPoint Energy's incentive on off system sales[82] and allocations among classes were calculated

[82] In Docket No. G008/GR-08-1075, the Commission allowed CenterPoint Energy to earn an incentive equal to the approved overall rate of return on its off-system sales. On page 14 of its AAA Report, CenterPoint Energy's incentive totaled $756,294 ($9,348,509 - $8,592,215). Thus, CenterPoint Energy used the approved overall rate of return approved of 8.09 percent ($756,294/8,592,215).

correctly. Thus, the Department concludes that CenterPoint is in compliance with the filing requirements in Docket No. 08-1075.

Docket No. G999/AA-12-756. The Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-up Proposals, and Setting Further Requirements* (Docket No. 12-756) required all regulated gas utilities to prospectively recover balancing service costs SMS or LMS and credit the utility's analogous penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that could reasonably be implemented. CenterPoint Energy complied with the Order by moving the balancing costs to commodity in its December 1, 2013 PGA, Docket No. G008/AA-13-1107.

Based on its review, the Department recommends that the Commission accept CenterPoint Energy's FYE14 true-up.

3. Summary and Recommendations

The Department concludes that CenterPoint Energy's FYE14 annual automatic adjustment report is complete with respect to the filing requirements in Minnesota Rules 7825.2390 through 7825.2920. Based on its review, the Department recommends that the Commission:

- accept CenterPoint Energy's FYE14 true up, Docket No. G008/AA-14-752; and
- allow CenterPoint Energy to implement its true up, as shown in Department Attachment G10 of the *AAA Report*.

F. XCEL GAS

1. Recovery of Gas Costs and True-Up Calculations

On August 29, 2014, Xcel Gas submitted its annual true-up filing, Docket No. G002/AA-14-736 in compliance with Minnesota Rule 7825.2810. Based on its review, the Department concludes that Xcel Gas' filing is complete with respect to Minnesota Rules 7825.2390 through 7825.2920.

According to Xcel Gas' August 29, 2014 true-up filing, the Company under-recovered gas costs by $50,148,451, or approximately 10.47 percent, during the reporting period, with a cumulative under-recovery of approximately 10.43 percent.[83] By customer class, Xcel Gas reported under-recoveries for the current reporting period as follows:

[83] The figure of 10.43 percent represents the cumulative general system under-recovery of $49,982,264, which is the basis for the true-up adjustments. For a detailed breakdown of the true-up calculations, please see Xcel Gas' true-up filing, Docket No. G002/AA-14-736.

FYE14 Percent Over-Recovery/(Under-Recovery)[84]
(As filed on August 29, 2014 by Xcel Gas)

Class	
Residential	(9.24)
Commercial/Industrial (C/I)	(10.43)
Demand Billed	(12.32)
Small Interruptible (SVI)	(15.87)
Medium & Large Interruptible (M&LVI)	(15.02)
Total	(10.47)

Using the sales volumes forecasted by Xcel for the year ending August 31, 2015[85] results in the following true-up factors by class, as calculated by Xcel Gas in its August 29, 2014 filing:

True-Up Factors per Dekatherm (Dth) by Class
(As filed on August 29, 2014 by Xcel Gas)

Class	
Residential	$0.6830
C/I	$0.7634
Demand Billed Commodity	$0.7575
Demand Billed Demand	$(0.0717)
SVI	$0.9699
M&LVI	$0.7929

The Department's analysis of Xcel Gas' August 29, 2014 true-up calculation shows that the current year's deviation between Xcel Gas' gas-cost recoveries and actual gas costs was primarily caused by the following factors:

1. Demand Costs including Demand Billed costs: Xcel Gas over-recovered Minnesota demand costs by $7,394,847, or approximately 15.11 percent. The demand-cost over recovery also includes interruptible curtailment penalty revenue of $1,384,872 and capacity-release revenue of $212,643. Without these revenues, there was an over recovery of demand costs of $5,797,332 or approximately 11.84 percent. According to Xcel Gas, actual FYE14 sales were approximately 26.25 percent higher than forecasted for firm customers, resulting in the over-recovery of demand costs.[86]

As discussed further below, Xcel Gas has a Monthly Demand Cost True-Up Mechanism, approved in Docket No. G002/M-03-843. This mechanism is designed to offset swings in revenue collection caused by deviations from the forecasted normal weather. The mechanism collected an additional $3,594,643 of demand costs from customers during the FYE14 heating season due to weather and the cap on the amount of the adjustment per month. Xcel Gas states that without the mechanism its over-recovery of demand costs would have been approximately 22.45 percent.[87]

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84 Supporting spreadsheets with detailed calculations are contained in Department Attachment G11.

85 Xcel Gas' true up, Schedule B, page 2.

86 Xcel Gas' AAA Report, Attachment B, Schedule 3, page 3.

87 Xcel Gas' AAA Report, Attachment B, Sch. 3, p. 3 and true up, Schedule I.

The Department concludes that Xcel Gas' demand cost over-recovery appears to be reasonable.

2. Commodity Costs (including peak-shaving costs) – During FYE14 Xcel Gas under-recovered commodity costs by $57,543,298, or about 13.38 percent. Xcel Gas stated that the under-recovery was due to:

> … deviations between monthly forecasted prices and actual wholesale commodity gas prices. These price deviations during the 2013-2014 heating season (in particular January and February) were the result of extreme price volatility in the wholesale natural gas commodity market and higher than average customer demand for natural gas. On an average unit basis, the under-recovery is approximately 7.35 cents per therm. Because customer consumption varies by class from month to month and price deviation varies from month to month, individual classes had varying results.
>
> The cost of gas set in the monthly PGA is based on an estimate of the monthly index prices at various locations and on an assumed mix of baseload purchases, spot purchases and storage withdrawals. Incremental gas demand above the plan forecast is supported by incremental storage withdrawals and daily spot purchases. During the 2013-2014 winter heating season, we purchased significantly more daily spot gas than forecasted because of significantly colder than normal weather.
>
> Notably, during the 2013-2014 winter heating season, seven of the top ten natural gas consumption days in the USA occurred. (Table omitted.)
>
> Further, daily spot prices spiked to historically high levels many days this winter due to prolonged periods of extremely cold weather across the nation and supply interruptions such as occurred during the TransCanada pipeline event. The combination of the higher quantity of daily purchases and daily spot prices created the under-recoveries.[88]

The Department appreciates Xcel Energy's thorough explanation of the commodity under recovery. Based on this information and the Department's expectations of commodity under recovery for the heating season, the Department concludes that Xcel Energy's under recovery of commodity costs appears to be reasonable.

2. Compliance and/or Supplemental Reporting Requirements

Docket No. G002/M-94-103. The Commission required Xcel Gas to return all past, present, and future capacity release revenue from all sources to firm customers using Federal Energy

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[88] Xcel Gas' AAA Report, Attachment B, Schedule 3, page 4.

Regulatory Commission (FERC) Account 805.1. Based on Xcel Gas' true up Schedule H, it appears that Xcel Gas 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 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, in Attachment G of its AAA report, that no firm transportation customers incurred "additional charges" for unauthorized use of gas, and Xcel Gas did not receive any such money during the current true-up period.

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

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

Xcel Gas complied by submitting the required information in Attachment A, Schedule 5, Attachment G, pages 2-4 and Attachment G, Schedule 2 of its AAA report. The Department discusses Xcel Gas' hedging costs in Section III, part O, of this *Report*.

Docket Nos. G002/M-03-843, G002/M-06-681, G002/M-08-456, G002/M-11-203, and G002/M-14-171 (Demand Cost Mechanism). On June 11, 2004, the Commission approved a Monthly Demand-Cost True-Up Mechanism, with requirements, and granted Xcel Gas a variance to Minnesota Rule 7825.2700, subpart 5 until September 30, 2006. The Monthly Demand-Cost True-Up Mechanism was implemented in October 2004. In the above dockets, the Commission approved extensions of the program until September 30, 2017.

The mechanism should result in billing rates that are:

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

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

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

Xcel Gas' FYE14 true-up filing, Schedule (I), includes the required information. Since the inception of this program, the demand-cost recovery results have been as follows:

	With Program Recovery		Without Program	
Year	Over/(Under)[89]	Percent	Over/(Under)	Percent
FYE05	$(652,620)	(1.1)	$(3,719,363)	(6.0)
FYE06	$(3,190,837)	(6.0)	$(6,327,057)	(11.9)
FYE07	$4,350,806	8.3	$703,577	1.3
FYE08	$2,628,294	6.1	$3,496,826	8.1
FYE09	$2,433,476	5.5	$3,595,452	8.1
FYE10	$341,457	(0.74)	$846,099	(1.82)
FYE11	$1,784,013	3.71	$2,538,677	5.27
FYE12	$(4,963,775)	(9.96)	$(7,529,571)	(15.11)
FYE13	$2,376,086	4.74	$2,069,183	4.12
FYE14	$7,394,847	15.11	$10,989,489	22.45

As shown above, except for FYE07 and FYE13, the program continues to match costs better within the true-up year than would have been the case without this program. In FYE14 actual over recovery of $7,394,847 outperformed the hypothetical over recovery of $10,989,489. The Department concludes that Xcel Gas complied with the filing requirements in the Commission's *Order* in Docket No. G002/M-03-843.

Docket No. G999/AA-08-1011. As noted above, the Commission directed Xcel Gas, CenterPoint, and MERC to provide the Department with information about their hedging programs, beginning in fiscal-year 2010. Xcel Gas provided this required information in Attachment G, Schedules 3, 4, and 5 in its original filing. The Department discusses Xcel Gas' hedging costs in Section III, part O, of this *Report*.

Docket No. G002/M-09-852. On February 18, 2010 the Commission approved Xcel Gas' variance for a natural gas Capacity Utilization Program for its gas distribution and electric generation business units as a three-year pilot program and required Xcel Gas to report in the AAA each individual transaction showing quantities and cost, the specific accounting entries and a brief explanation of the transaction.

89 For comparison purposes, the variances are calculated using non-prorated data (*i.e.,* calendar month rather than billing month data).

During FYE14, the Capacity Utilization Program resulted in net savings to Xcel Gas of approximately $68,500 including capacity sharing transactions savings of approximately $9,500 and avoided storage fees of approximately $59,000 through storage nettings. Xcel Gas explained that due to administrate oversight, the company continued to utilize this mechanism on five occasions after the expiration of the variance.

According to Xcel Gas, it plans on requesting an extension of the variance this spring.[90] Xcel Gas stated:

> Originally the Company was not planning to file to extend the program because the savings realized under the program for both gas and electric customers was modest during the period of the pilot program. However, we anticipate that the net benefits under the program may increase starting with 2015-2016 heating season if FERC approves certain changes to the gas and electric trading days. As part of its gas-electric coordination initiative, FERC is evaluating whether the deadline for electric markets, including MISO, to publish next day generator schedules should be moved up ahead of the deadline to purchase and schedule natural gas. If this change to the electric and gas trading deadlines is made, we will have more certainty around the availability of firm pipeline transportation capacity for sharing. Even if this change is not made, ratepayers will still benefit modestly by extending the capacity sharing program as benefits were successfully demonstrated for both gas and electric customers.

Additionally, Xcel Gas explained that net savings are given to ratepayers:

> The net savings were given back to customers as part of the annual true-up calculation and subsequent year's true-up factors. Savings and costs from the program were entered into existing expense accounts that already flowed through the annual true-up calculation. The savings/costs reduced/increased the total commodity or demand expenses, depending on the type of transaction, for the true-up year. Customers received the benefit of these savings in the annual true-up factors included in the Purchased Gas Adjustment calculations.

Xcel Gas is in compliance with the filing requirements in Docket No. G002/M-09-852. However, the Department recommends that in its Reply Comments, Xcel Gas request a variance for the five occasions where Xcel Gas continued to use the program during 2013-2014 after the expiration of the original variance.

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90 Per Department Information Request No. 29.

Docket No. G999/AA-12-756. The Commission's November 14, 2013 *Order Accepting Gas Utilities' Automatic Adjustment Reports and True-up Proposals, and Setting Further Requirements* (Docket No. 12-756) required all regulated gas utilities to prospectively recover balancing service costs SMS or LMS and credit the utility's analogous penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that could reasonably be implemented. Xcel Gas complied with the Order by moving the balancing costs to commodity in its November 1, 2013 PGA, Docket No. G002/AA-13-997.

Based on its review, the Department recommends that the Commission accept Xcel Energy's FYE14 true-up.

3. Summary and Recommendations

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

- accept Xcel Gas' FYE14 true-up, Docket No. G002/AA-14-736; and
- allow Xcel Gas to implement its true-up, as shown in Department Attachment G11 of the *AAA Report*.

The Department also recommends that Xcel Gas address in its Reply Comments a variance for the five occasions where Xcel Gas continued to use the program discussed above during 2013-2014 after the expiration of the original variance.

III. ADDITIONAL INFORMATION

A. AVERAGE ANNUAL RESIDENTIAL CUSTOMER BILLS

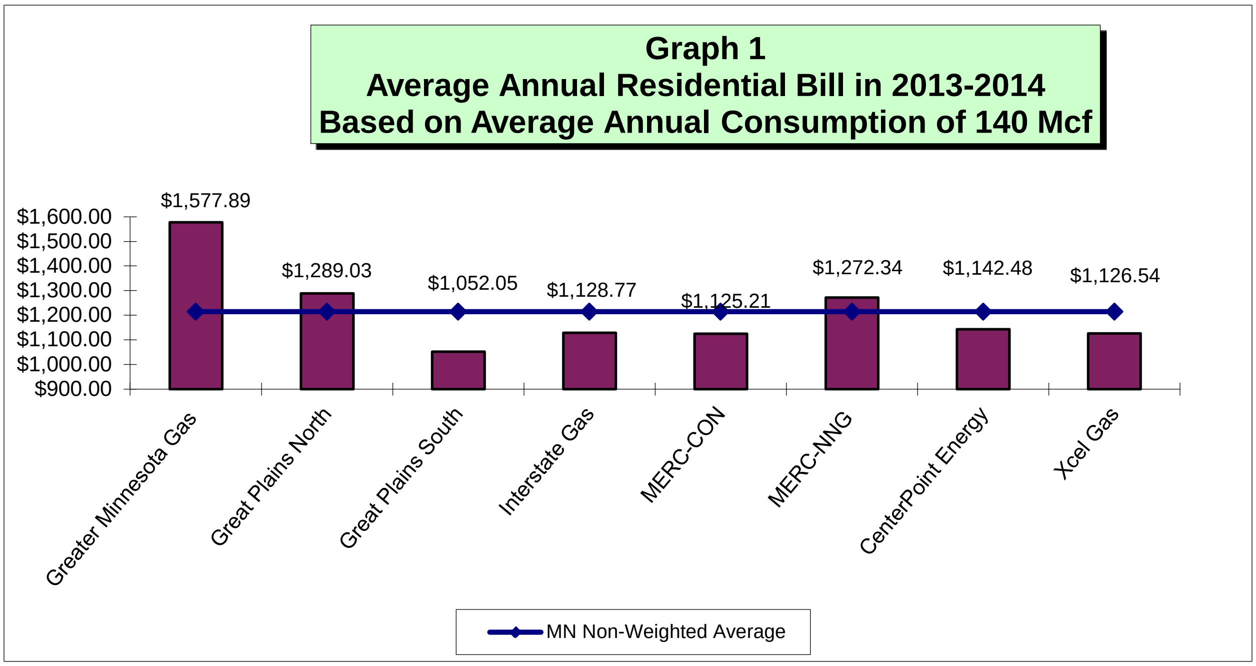
Using data supplied by the utilities in their responses to Department Information Request No. 1, the Department compared the average annual bills of residential customers for each regulated gas utility in Minnesota. This information is summarized in Graph 1 below and in Department Attachment G13. As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

- customer charge;
- per-unit energy consumption rate; and
- average customer consumption of 140 Mcf per year.[91]

[91] 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.

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.[92]

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.[93] 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 range from a high of $1,577.89 for customers served by GMG to a low of $1,052.05 for customers served by Great Plains South District PGA.[94]

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92 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.

93 Minnesota LDCs generally file demand entitlement petitions on, or about, July or August 1 of each calendar year. However, demand entitlement filings during other parts of the year also occur.

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

Table G4 below shows the actual average residential bills and average use for each system during the present reporting period using the data supplied in response to Department Information Request No. 1.

TABLE G4
Average Annual Residential Bill and Average Use per Utility
for the FYE14 Reporting Period

Utility	System	Average Use (Mcf)[96]	**Annual Bill Rankings**[97]	Total Annual Bill ($)	Average[95] Cost per Mcf ($)	Annual Customer Charges ($)
GMG		100 (3)	**8**	$1,154.10	$11.56	$102.00
Great Plains	North	91 (2)	**5**	$864.30	$9.51	$78.00
	South	86 (1)	**1**	$672.87	$7.87	$78.00
Interstate Gas		102 (5)	**3**	$841.75	$8.22	$60.00
MERC	CON	101 (4)	**2**	$840.80	$8.34	$108.55
	NNG	102 (5)	**7**	$954.04	$9.38	$108.55
CenterPoint Energy		106 (6)	**6**	$886.22	$8.39	$99.51
Xcel Gas		102 (5)	**4**	$848.98	$8.34	$108.00

As shown in Table G4, based on actual consumption, CenterPoint Energy experienced the highest average consumption (106 Mcf), and GMG had the highest average annual residential bill ($1,154.10) during FYE14.[98]

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95 The average cost per Mcf may be different from the annual bill shown in column (3) divided by the average use shown in column (1) due to rounding of the average usage.

96 The average annual usage amount reported in response to Department Information Request No. 1 is not weather normalized but reflects the different heating degree days based on location. The numbers in the parentheses are the rankings of the use per customer, where tied rankings are assigned the same number. The highest number is six in this ranking.

97 Rankings throughout this report are listed in the format from lowest to highest (*e.g.,* average use, cost, and rate).

98 From FYE98 through FYE04, MERC-NMU (then Aquila-NMU) experienced both the highest average consumption and corresponding highest average residential bill. MERC-NMU's average consumption and corresponding average bill were as follows:

FYE98 .... 138 Mcf................................ $834.26
FYE99 .... 114 Mcf................................ $649.02
FYE00 .... 116 Mcf................................ $720.24
FYE01 .... 153 Mcf.............................. $1,338.20
FYE02 .... 141 Mcf................................ $841.33
FYE03 .... 157 Mcf.............................. $1,127.90
FYE04 .... 147 Mcf.............................. $1,220.25

Since FYE04, the following utilities had the highest consumption and average residential bills:

FYE05 Great Plains Crookston...... .... 90 Mcf $961.40
FYE06 Greater Minnesota RS-2.... .... 93 Mcf $1,167.74

There are two qualifications needed to the information provided in Graph 1, Table G4, and Department Attachment G13. First, the costs that utilities incur often are determined by a number of factors, such as: load factor, number of customers, mix of firm and interruptible customers, number of available pipeline systems, weather, past contracts with pipelines and suppliers that are still in effect, access to storage, and provisions of pipeline service as approved by the FERC (*e.g.*, imbalance penalties).

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

B. ANNUAL AVERAGE GAS COSTS

Table G5 below compares the total system annual averages of both the PGA recovered and the actual incurred commodity costs. The figures in Table G5 represent the per-unit[99] commodity costs incurred by the utilities and passed on to ratepayers in the monthly PGAs, as reported in the utilities' true-up filings. Certain tables in this report provide the Minnesota weighted average and the Minnesota non-weighted average amounts. The Department includes the non-weighted average since the weighted average is dominated by Minnesota's largest natural gas provider, CenterPoint Energy.

FYE07 Greater Minnesota RS-2....	95 Mcf	$1,060.31
FYE08 CenterPoint Northern and Great Plains Crookston	100 Mcf	$1,205.75
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

[99] The Department uses Mcf (one thousand cubic feet) in certain of its tables to represent units even though the units may actually be Dth (heat adjusted Mcf).

TABLE G5
FYE14
Total Weighted Average Cost of Commodity
PGA Recovered Versus Actual Incurred[100]

Utility/System		Recovered PGA Commodity Rate ($/Mcf)	Actual Incurred Commodity Cost ($/Mcf)	Percent Over / (Under) Recovery
Greater Minnesota		$5.4390	$5.5679	(2.32)%
Great Plains	North	$5.3271	$6.3654	(16.31)%
	South	$4.4510	$5.3973	(17.53)%
Interstate Gas		$4.5894	$4.5932	(0.08)%
MERC	CON	$4.7650	$5.4855	(13.13)%
	NNG	$4.6696	$5.4122	(13.72)%
CenterPoint Energy		$5.1693	$5.5865	(7.47)%
Xcel Gas		$4.7271	$5.4572	(13.38)%
MN Weighted Average		**$4.9686**	**$5.5247**	**(10.07)%**
MN Non-Weighted Average		**$4.8922**	**$5.4831**	**(10.78)%**

Table G5 demonstrates that all of the PGA systems under-recovered commodity costs. During the reporting period, Great Plains South had the greatest under-recovery of commodity costs, with an under-recovery of approximately 17.53 percent.

100 The numbers used and the detailed calculations are contained in Department Attachment G15.

Table G5a below shows the FYE14 increase or decrease in the Minnesota non-weighted average commodity costs over previous years' costs back to FYE99. The figures below are nominal costs and are not adjusted for either inflation or weather conditions. Based on these data, during FYE14, the actual Minnesota non-weighted average commodity cost of gas was $5.4831 per Mcf, which represents an approximately 59 percent increase in prices from the FYE13 reporting period.[101]

TABLE G5a
Non-Weighted, Nominal Average Commodity Costs

Reporting Period	Cost ($/Mcf)	FYE14 Increase/(Decrease) Over Other Yrs.
FYE14	$5.4831	
FYE13	$3.4442	59%
FYE12	$3.5238	56%
FYE11	$4.3001	28%
FYE10	$4.7259	16%
FYE09	$6.1826	(11)%
FYE08	$7.4936	(27)%
FYE07	$7.6177	(28)%
FYE06	$8.8345	(38)%
FYE05	$6.3167	(13)%
FYE04	$5.3364	3%
FYE03	$4.7441	16%
FYE02	$2.6524	107%
FYE01	$6.0288	(9)%
FYE00	$2.5356	116%
FYE99	$1.9876	176%

As shown above in Table G5, the analysis of "PGA Recovered versus Actual Incurred" commodity costs 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 fuel reports to develop a "total system" average cost of gas analysis as shown below in Table G6. The comparison of total costs per Mcf experienced by each utility presents another useful analytical tool to compare recovered versus actual gas costs. Below is a summary of the actual total system gas costs experienced during the reporting period by Minnesota gas utilities.

101 The beginning of this report discussed the increase in natural gas costs in general, whereas this table reflects retail commodity rates.

TABLE G6
FYE14
Total System Gas Costs (Demand and Commodity)[102]

Utility/System	PGA Recovered ($/MMBtu)	**Rankings**	Current-Period Actual Incurred Gas Cost ($/MMBtu)	**Rankings**	Actual Over/(Under) ($/MMBtu)	Percent Recovery
Greater Minnesota	$6.1581	6	$6.1749	6	$(0.0169)	(0.27)%
Great Plains						
North	$6.3469	8	$7.2199	8	$(0.8730)	(12.09)%
South	$5.2008	1	$6.0174	2	$(0.8166)	(13.57)%
Interstate Gas	$5.8225	5	$5.4969	1	$0.3256	5.92%
MERC						
Consolidated	$5.4997	3	$6.0604	3	$(0.5607)	(9.25)%
NNG	$6.2540	7	$6.6852	7	$(0.4312)	(6.45)%
CenterPoint Energy	$5.6631	4	$6.0814	5	$(0.4183)	(6.88)%
Xcel Gas	$5.4421	2	$6.0784	4	$(0.6363)	(10.47)%
MN Weighted Avg.	**$5.6607**		**$6.1479**		**$(0.4872)**	**(7.92)%**
MN Non-Weighted Avg.	**$5.7984**		**$6.2268**		**$(0.4284)**	**(6.88)%**

Total system PGA-recovered and actual-incurred gas costs, as shown in Table G6, provide a comparison of the utilities' total system gas costs (demand and commodity). The first observation that can be garnered from this table is that seven of the eight PGA systems under-recovered total gas costs during the reporting period. Of those utilities that under-recovered gas costs, there were six that under-recovered in excess of five percent. The greatest under-recovery was reported by Great Plains South at 13.57 percent. The one utility that over-recovered costs, Interstate Gas, over-recovered by 5.92 percent. Great Plains North had the highest actual gas cost and Interstate Gas had the lowest actual gas cost. The smallest over-recovery was reported by Greater Minnesota at 0.27 percent.

Table G6a below shows the FYE14 increase or decrease in Minnesota non-weighted average total system gas costs over each of the previous years' rates. The figures below are nominal costs and are not adjusted either for inflation or weather conditions. Based on these data, during FYE14, the actual Minnesota non-weighted average total system cost of gas was $6.2268 per Mcf, representing an approximately 44 percent increase from the FYE13 reporting period.

102 The numbers reported in Table G6 are from the true-up filing submitted by each utility. The numbers and the detailed calculations used are contained in Department Attachments G12, G12a, and G16 through G18.

TABLE G6a
Non-Weighted Average Total System Gas Costs

Reporting Period	Rate ($/Mcf)	FYE14 Increase/(Decrease) Over Other Yrs.
FYE14	$6.2268	
FYE13	$4.3327	44%
FYE12	$4.7892	30%
FYE11	$5.3295	17%
FYE10	$5.7062	9%
FYE09	$6.9548	(10)%
FYE08	$8.3613	(26)%
FYE07	$7.8131	(20)%
FYE06	$9.7936	(36)%
FYE05	$7.2930	(15)%
FYE04	$6.2626	(1)%
FYE03	$5.5635	12%
FYE02	$3.4941	78%
FYE01	$6.8382	(9)%
FYE00	$3.4529	80%
FYE99	$2.8627	118%

C. PER-UNIT MARGIN CHARGED TO RESIDENTIAL CUSTOMERS

Using data collected from information requests to all gas utilities, the Department developed a list of the annual FYE14 per-unit margins charged by each utility, by pipeline system, to residential customers. Margins are approved by the Commission only at the time of a general rate case. Table G7 below presents the Department's summary of the per-unit margins as of June 30, 2014.

TABLE G7
FYE14
Actual Per-Unit
Margin Rate By PGA System
Charged to Residential Customers

Utility	System	Non-Gas Margin ($/Mcf)
Greater Minnesota[103]		$4.4433
Great Plains[104]	North	$1.7864
	South	$1.4024
Interstate Gas		$1.9769
MERC[105]	CON	$2.1022
	NNG	$2.1022
CenterPoint Energy[106]		$1.7552
Xcel Gas[107]		$1.8591
MN Non-Weighted Average Margin		**$2.1785**

As shown on Table G7, GMG and MERC have the highest residential non-gas margins. The Department notes that GMG is a relatively small company and, thus, its fixed costs are spread over fewer customers. The two lowest residential non-gas margins are for Great Plains South and CenterPoint Energy.

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103 Greater Minnesota's most recent rate case was filed in Docket No. G022/GR-09-962. Greater Minnesota's non-gas margin rates were last changed as of November 1, 2010.

104 Great Plains' most recent rate case was filed in Docket No. G004/GR-04-1487. The non-gas margins for Great Plains' two systems have been updated based on changes in the Conservation Improvement Program (CIP) tracker account.

105 MERC's non-gas margins changed effective January 1, 2014 pursuant to the Commission's approval of interim rates in MERC's most recent rate case, Docket No. G011/GR-13-617.

106 CenterPoint Energy's non-gas margins changed effective October 1, 2013 pursuant to the Commission's approval of interim rates in CenterPoint Energy's most recent rate case, Docket No. G008/GR-13-316.

107 Xcel Gas' non-gas margin rates were changed with the implementation of final rates on May 1, 2010 in rate case Docket No. G002/GR-09-1153.

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

The Department used data from responses to Department Information Requests to develop a summary of each gas utility's peak-day demand profile, load factor, and reserve margin. Table G9 below presents a summary of this information.

TABLE G9[108]
FYE14
Firm Peak-Day Demand Profiles

Utility/System	Firm Design-Day Demand (Mcf)	Firm Peak-Day Demand Deliverability (Mcf)	Annual Firm Throughput (Mcf)	Annual[109] Firm Load Factor (Percent)	Reserve Margin[110] (Percent)
Greater Minnesota[111]	8,917	9,559	899,711	31.28%	7.20%
Great Plains[112]					
North	14,140	15,000	1,600,823	33.46%	6.08%
South	15,293	15,645	1,595,713	30.65%	2.30%
Interstate Gas[113]	13,035	14,219	1,469,802	35.86%	9.08%
MERC					
Consolidated[114]	50,048	52,959	4,509,638	31.50%	5.82%
Northern[115]	245,878	256,385	21,397,632	27.44%	4.27%
CenterPoint Energy[116]	1,288,000	1,340,099	119,582,224	30.16%	4.04%
Xcel Gas[117]	706,935	749,325	73,019,076	37.13%	6.00%
MN Totals	**2,342,246**	**2,453,191**	**224,074,619**	**31.90%**[118]	**4.74%**[119]

108 See Department Attachment G20.

109 The load factor equals the daily average firm throughput (annual firm throughput [from Table G9] divided by 365) divided by actual firm peak-day demand (from Table G10).

110 The reserve margin equals (using values from Table G9) the firm peak-day demand entitlement minus firm design-day demand divided by firm design-day demand.

111 Regarding the 2013-2014 period, the reserve margin is further discussed in Docket No. G022/M-13-730.

112 Regarding the 2013-2014 period, the reserve margins are discussed further in Docket No. G004/M-13-566.

113 Regarding the 2013-2014 period, the reserve margin is further discussed in Docket No. G001/M-13-579.

114 Regarding the 2013-2014 period, the reserve margin is further discussed in Docket No. G011/M-13-669.

115 Regarding the 2013-2014 period, the reserve margins are discussed further in Docket No. G011/M-13-670.

116 Regarding the 2013-2014 period, the reserve margin is further discussed in Docket No. G008/M-13-578.

117 Regarding the 2013-2014 period, the reserve margin is further discussed in Docket No. G002/M-13-663.

118 This percent represents the weighted average of Minnesota gas utilities' load factors.

119 This percent represents the weighted average of Minnesota gas utilities' reserve margins.

As shown above, Minnesota's gas utilities exhibit a firm load factor between approximately 27.44 percent for MERC-NNG and approximately 37.13 percent for Xcel Gas.

Also, the Department reports that the reserve-margin percentage, which includes each utility's contracted transportation and peak-shaving capacity, was approximately 4.74 percent during the reporting period. This level represents a decrease in the statewide reserve margin of 0.60 percent over the 5.34 percent figure reported in the last AAA Report. As shown in the table above, the reserve margins range from approximately 2.30 percent for Great Plains South to approximately 9.08 percent for Interstate Gas.

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

The Department also used the data from responses to information requests to develop a comparison of each gas utility's firm peak-day demand deliverability to its actual firm peak-day use. Table G10 below presents a summary of this information.

TABLE G10
Comparison of Peak-Day Demand Usage

Utility/System	Firm-Peak Day Demand Deliverability[120] (Mcf)	Actual Firm Peak-Day Usage (Mcf)	Actual Firm Requirement (%)	Actual Peak Date
Greater Minnesota	9,559	7,880	82	1/6/14
Great Plains				
North	15,000	13,109	87	1/5/14
South	15,645	14,266	91	1/5/14
Interstate Gas	14,219	11,230	79	1/6/14
MERC				
Consolidated	52,959	39,220	74	1/5/14
NNG	256,385	213,608	83	1/6/14
CenterPoint Energy	1,340,099	1,086,330	81	1/6/14
Xcel Gas (MN Jurisdiction)	749,325	538,794	72	1/6/14
MN Totals	**2,453,191**	**1,924,437**	**78**	

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

As Table G10 reflects, all of the regulated gas utilities in Minnesota were able to meet their actual firm peak-day FYE14 sendout within their proposed demand entitlement levels. The peak day for Minnesota regulated gas utilities occurred on two different days during the 2013-2014 heating season. For GMG, Interstate Gas, MERC-NNG, CenterPoint Energy, and Xcel Gas the peak day occurred on January 6, 2014. For Great Plains North and South, and MERC-Consolidated the peak day occurred on January 5, 2014. The utilities had an aggregate peak-day usage or sendout of 1,924,437 Mcf. However, the companies planned for an aggregate peak of 2,453,191 Mcf, implying that approximately 78 percent of the planned peak-day sendout was actually used during FYE14. This result represents an 11 percent increase in the peak-day usage compared to the previous heating season.

E. DAILY DELIVERY VARIANCE CHARGES

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

Interstate pipelines (*e.g.,* Northern Natural Gas Co., Viking Gas Transmission Co.) impose balancing penalties on their shippers, such as Minnesota utilities, when these shippers do not nominate their daily capacity amounts within a given percentage of the actual entitlement level used. On Northern's system, these charges (or penalties) are known as positive, negative, or punitive daily delivery variance charges (DDVCs). Northern changed its DDVC rate structure effective October 1, 2009.[121] The current Northern DDVC cost structure for gas taken in excess of nominated levels is as follows:

121 See Northern Natural Gas Company's FERC Gas Tariff, Fifth Revised Vol. No. 1, 82 Revised Sheet No. 53, superseding Volume 1, 81 Revised Sheet No. 53, effective October 1, 2009.

TABLE G11
NNG's DDVC Structure[122]

Type	Current Charge
Negative DDVC	$0.40[123]
Positive DDVC	$1.00[124]
Punitive DDVC[125]	5 x SMS rate[126]
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 each utility incurred.[127] Table G12 below provides a summary of the pipeline penalties incurred during the FYE14 reporting period.

122 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 which Northern's system integrity is threatened and SBA provisions are not adequate in maintaining pipeline operations. See Northern Natural Gas' Tariff Sixth Revised Sheet 292.

123 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.

124 *Id.*

125 *Id.*

126 SMS is Northern's "System Management Service" which provides additional tolerances for shippers beyond the 5 percent tolerance. The SMS rate is calculated on a monthly reservation fee basis.

127 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 G12[128]
FYE14
Daily Delivery Variance Charges[129]
Incurred By Utility

Utility	DDVC (Mcf)	DDVC ($)	Total Gas Costs Incurred ($)	Percent of Total Costs Represented by Penalties
Greater Minnesota	4,216	$6,717	$6,360,602	0.1056%
Great Plains	40,421	$31,412	$29,293,442	0.1072%
Interstate Gas	0	$0	$10,119,966	0.0000%
MERC-Consolidated	0	$0	$40,238,905	0.0000%
MERC-NNG	26,330	$10,297	$191,434,993	0.0054%
CenterPoint Energy	162,693	$69,897	$902,777,336	0.0077%
Xcel Gas	217,941	$50,959	$479,032,245	0.0106%
MN Totals	**451,601**	**$169,282**	**$1,659,257,489**	**0.0102%**

As shown above, the penalties incurred by the gas utilities range from $0 for Interstate Gas and MERC-Consolidated to $69,897 for CenterPoint Energy. On a percentage basis, the penalties range from 0 percent for Interstate Gas and MERC-Consolidated to approximately 0.1072 percent for Great Plains.

In their responses to the Department's Information Request No. 7, utilities identified the amount of each type of DDVC imposed. Table G13 below provides a summary of the type of DDVC penalty incurred during the FYE14 reporting period.

128 Table G12 summarizes the data provided in Department Attachment G14.

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

TABLE G13[130]
FYE14
Amount of DDVCs Incurred by Type

Utility	Positive & Negative	Punitive	Total	Percent of Total MN DDVCs
Greater Minnesota	$3,075	$3,642	$6,717	3.97%
Great Plains	$31,412	$0	$31,412	18.56%
Interstate Gas	$0	-	$0	0.00%
MERC-Consolidated	$0	-	$0	0.00%
MERC-NNG	$10,297	-	$10,297	6.08 %
CenterPoint Energy	$69,897	-	$69,897	41.29%
Xcel Gas	$50,959	-	$50,959	30.10%
MN Totals	**$165,640**	**$3,642**	**$169,282**	**100.00%**

As shown above, all Minnesota regulated gas utilities except Interstate Gas and MERC-Consolidated incurred some type of DDVC during the FYE14. Total DDVC penalties for all gas utilities increased by $150,629 (from $18,653 for FYE13 to $169,282 for FYE14), or approximately 808 percent, from the amount reported in FYE13. Greater Minnesota experienced punitive penalties during FYE14 totaling $3,642. The Department notes that NNG's Penalty Charge Credits received by each utility and included in the true ups for FYE14 are separately shown below Table G15.

The Department recognizes that nominations require careful analysis and consistent forecasting methods. Major decisions regarding nominations must be made by 11:30 a.m. the day before the gas day.[131] An intraday nomination is a nomination electronically submitted after the initial nomination. Intraday nominations may be used to nominate new market or supply and can be used to request increases or decreases in total flow, changes to receipt points, or changes in delivery points of scheduled gas.[132] There are three opportunities to make intraday nominations:

- by 6:00 p.m. the day before the gas day (to be effective at 9:00 a.m. on the gas day);
- by 10:00 a.m. on the gas day (to be effective at 5:00 on that day); and
- by 5:00 p.m. on the gas day (to be effective at 9:00 p.m. on that day).

The Department also recognizes that a certain level of positive and negative DDVCs is a natural result of daily weather fluctuation, advance nomination decisions, and limited opportunities to make intraday nominations. Moreover, a utility's ability to make appropriate intraday nominations can be limited by the information the utility has from customers about expected gas use on a particular day. Nevertheless, utilities have various tools with which to

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130 Table G13 summarizes the data provided in Department Attachment G14.

131 See Northern Natural Gas Company's FERC Gas Tariff, Fifth Revised Vol. No. 1, Fifth Revised Sheet No. 257, issued August 1, 2002.

132 *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.

minimize DDVC penalties, such as using pipeline storage facilities and peak-shaving plants or curtailing interruptible customers as discussed further below.

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

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

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

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

The total balancing and curtailment penalties imposed during the reporting period increased by $4,206,104, or approximately 710 percent, from the amount imposed during the FYE13 reporting period, $592,743, to the amount imposed during the FYE14 reporting period, $4,798,847. Based on the information in each utility's responses to Department information requests, it appears that Xcel Gas increased curtailment penalties from $6,322 to $1,384,872. On the other hand, CenterPoint Energy's balancing revenue increased from $4,257 to $916,066. Curtailment penalties and balancing penalties are discussed below.

1. Curtailment Penalties

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

Below is a summary of the revenue from curtailment penalties imposed on interruptible customers during FYE14.

TABLE G14[133]
FYE14
Revenue from Curtailment Penalties

Gas Utility	Total Penalties	Percent of Total Penalties	Total Costs Incurred[134]	Penalties as a Percent of Total Costs Incurred
Greater Minnesota	$0	0.00%	$6,360,602	0.0000%
Great Plains	$6,721	0.21%	$29,293,442	0.0229%
Interstate Gas	$37,118	1.14%	$10,119,966	0.3668%
MERC-Consolidated	$335,845	10.33%	$40,238,905	0.8346%
MERC-NNG	$570,860	17.56%	$191,434,996	0.2982%
CenterPoint Energy	$916,066	28.17%	$902,777,336	0.1015%
Xcel Gas	$1,384,872	42.59%	$479,032,245	0.2891%
MN Total	**$3,251,482**	**100.00%**	**$1,659,257,489**	**0.1960%**

As shown above, all of the utilities except Greater Minnesota imposed curtailment penalties on interruptible (or dual-fuel) customers. Penalties as a percent of total costs ranged from 0 percent (GMG) to 0.8346 percent for MERC-Consolidated. For the reporting period, the total amount of curtailment penalties was $3,251,482. This amount is an increase of $3,233,504 from the FYE13 figure of $17,564. The Department notes that revenues from curtailment penalties identified above are to be returned to all sales customers as a credit to demand cost in the annual true-ups.

The dramatic increase in curtailment penalty revenue over FYE13 is due to the extreme weather conditions during the 2013-2014 heating season, which led to a high number of interruption events compared to recent history. This level of curtailment penalty revenue for one year indicated that a significant amount of unauthorized gas was used during called curtailment events. The Department issued Information Request No. 18 (IR 18) requesting tariff information for interruptible customers, detail of all unauthorized gas usage during the 2013-2014 heating season, and penalties charged to the non-compliant customers.

a. <u>Unauthorized Use in FYE14</u>

Almost all of the Minnesota gas utilities experienced unauthorized gas service; GMG was the only utility that did not experience unauthorized gas use during a called interruption.

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133 The penalties listed in Table G14 are taken from the utilities' responses to Department Information Request No. 8.

134 The figures listed in the column entitled "Total Costs Incurred" in Table G14 are taken from the gas utilities' true-up filings. Total costs incurred include demand and commodity costs.

	Unauthorized Dth	Actual Annual Dth Sold	% of Sales
GMG	-	1,030,069	-
Great Plains	2,460.60	4,483,982	0.05%
Interstate Gas	3,773.52	1,841,021	0.20%
MERC	44,508.70	35,275,248	0.13%
CenterPoint Energy	69,660.40	148,449,728	0.05%
Xcel Gas[135]	126,589.68	78,808,906	0.16%

Great Plains had the smallest volume of unauthorized gas taken during its curtailment events, and usage was concentrated to 27 customers.

Interstate Gas had the second lowest unauthorized gas usage but the highest percentage to annual Dth sold, and usage was concentrated to 26 customers.

Of MERC's approximately 600 interruptible customers, roughly 200 of those customers took unauthorized gas during one or both curtailment events.

CenterPoint Energy has approximately 2,700 customers, about 700 of which took unauthorized gas during called curtailments.

Xcel Gas had the most unauthorized gas use by volume, and one of the highest use by percentage of annual sales. Of Xcel Gas' interruptible customers, 197 or about 44 percent, did not comply with at least one of the interruptions during the 2013-2014 heating season.

b. <u>Customer Concentration and Habitual Offenders</u>

During its review of the curtailment data, the Department noticed a concentration of unauthorized use by a few non-compliant customers for Great Plains, Interstate Gas, and Xcel Gas. During the 2013-2014 heating season:

- three customers used 1,506 Dth, or approximately 60 percent, of Great Plains' total unauthorized gas usage;
- four customers used 2,097 Dth, or approximately 56 percent, of Interstate Gas' total unauthorized usage: and
- one customer used over 72,000 Dth, or approximately 57 percent, of Xcel Gas' total unauthorized usage.

While the concentration of customer use for Great Plains and Interstate Gas should be addressed by Department recommendations discussed below, the customer use in Xcel Gas' case where one customer was responsible for over half of Xcel Gas' total unauthorized usage was particularly alarming. The Department sent Information Request No. 22 to inquire whether Xcel pursued any remedy for this customer's repeated non-compliance.

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135 Xcel Gas' initial response to IR 18 indicated that unauthorized gas use during the 2013-2014 heating season was 145,147.75 Dth. In its response to DOC Information Request 22, it corrected data for two customers, reducing the total unauthorized gas used to 122,980.25 Dth.

Xcel Gas stated that its representatives were in contact with its interruptible customers throughout the curtailment periods. In the case of this customer, there was a physical failure of their alternate fuel equipment serving one of their boilers. Due to the cold temperatures, the equipment was not repaired before the last curtailment period. Xcel Gas also stated that it continuously monitored the gas distribution system throughout the interruptible curtailment periods, and since there was no system impacts due to the customers discussed above, no consideration of shutting off natural gas service was contemplated for this or other customers.

While the Department recognizes that there was no impact to Xcel Gas' system due to this customer's non-compliance to called curtailments, this specific situation speaks to a larger issue about the utilities' tariff provisions regarding non-compliant interruptible customers. When interruptible customers operate in a manner outside of the tariff (*e.g.*, consuming gas during a called interruption), it can impair firm system reliability. System reliability is designed for only firm customers based on a forecasted peak day; in other words, when a curtailment is called it is assumed that interruptible customers stop using gas. If for any reason, interruptible customers have not stopped consumption when a curtailment is called, the possibility exists that system reliability will be impaired and firm customers may lose service.

For this reason, it is important for utilities, not just customers, to follow their tariffs. All of the Minnesota regulated gas utilities, except for Interstate Gas, have a specific provision allowing the utilities to shut off gas supply to interruptible customers if they do not comply with a called curtailment. Yet, no utility actually shut off gas supply to any non-compliant customers during the 2013-2014 heating season. The Department urges the utilities to be more aggressive with enforcing its tariffs when customers do not comply with called curtailments.[136]

If an interruptible customer does not comply with a called curtailment event, it is either for economic or non-economic reasons. While the economic incentive should be addressed through curtailment penalties, the non-economic reasons can be vast and diverse, and more difficult to address directly. But ultimately, if a customer is taking unauthorized gas for non-economic reasons, it is more than likely that customer should be taking firm rather than interruptible service. Effective November 1, 2014, Xcel Gas added the following provision to its tariff,[137]

> An interruptible customer's unauthorized use of gas during an interruption is a breach of the terms of service. Xcel Energy reserves the right to discontinue service for such unauthorized use of gas and/or move non-compliant customers to a different rate class. If an interruptible customer's service is reconnected following a breach of service or unauthorized use of gas, the

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136 The Department would normally provide a recommendation for Interstate Gas to amend its tariff to be consistent with the other gas utilities' curtailment provisions. However, the agreement for MERC to purchase Interstate Gas' assets in Docket No. G001, G011/PA-14-107 is currently anticipated to close in the second quarter of 2015. At that point, Interstate Gas' customers will be covered under MERC's tariffs.

137 Minnesota Gas Rate Book – MPUC No. 2, Section No. 5, Sheet No. 12. This language was approved by the Commission in its October 17, 2014 Order in Docket No. G002/M-14-540.

customer will reimburse the company for the cost of reconnection.

MERC has similar language in its tariff[138] to disconnect an interruptible customer for willful or continued failure to comply with curtailment orders, but stops short of allowing the utility to move the customer to another rate class. The Department recommends that all utility tariffs, except Interstate Gas, have this provision which gives the utilities the right to revoke interruptible customer class status from habitually non-compliant interruptible customers by discontinuing service or moving the customer to firm service.

There are still several issues that remain unaddressed by this tariff language however, so the Department requests that each utility provide discussion on the following questions:

- What anticipated effects would the above recommended change to tariff language have on the utilities' demand entitlements?
- When should a utility remove a customer from interruptible service? Immediately? The following November 1? A different date?
- What notice, if any, is required from the utility to give to a customer before moving the customer to a different rate class? If none is required, how should notice be given?
- What are the specific triggers for a utility to remove a customer from interruptible service? Unauthorized usage over a pre-determined amount of dekatherms? A percentage of winter sales? Non-compliance with called curtailments more than once?
- How long would a customer be excluded from interruptible service before it could be reinstated into that rate class?
- What amount should be charged to be reinstated and what types of costs would be included in the charge?

The Department suggests the following, and welcomes discussion to refine the details, in addition to the topics listed above:

- Non-compliant interruptible customers should be evaluated by the utility after each heating season;
- Customers that cumulatively take unauthorized gas over a certain threshold, or do not comply with more than one called curtailment, in one heating season be removed from interruptible service and made firm customers as of the following November 1;
- Customers lose interruptible service for at least a year (November 1 through October 31);
- As a condition for reinstating interruptible service, the customer would be responsible for all costs of reconnection. For utilities that require a back-up system as a condition of service, reconnection costs should include the costs for

138 *General Rules, Regulations, Terms And Conditions*, Sheet No. 8.26.

the utility to physically inspect and test the customer's back up system before interruptible service is reinstated.[139]

c. *Demand Cost of Gas and Curtailment Penalties*

The expected level of peak-day consumption is used to set the demand, or capacity, portion of the cost of gas, which is only charged to firm customers. These capacity contracts are completed months, and sometimes years, in advance and cover multiple months, not just one day. Moreover, when NNG calls a System Overrun Limitation, there is no capacity available from NNG. When Interruptible customers use unauthorized natural gas, and therefore capacity, during a curtailment period, those customers are using capacity that was contracted for serving firm customers. This situation will not only threaten system reliability, as discussed above, but it can also increase costs for all customers.[140]

Based on interruptible customer behavior during the 2013-2014 heating season, it is apparent that current utility curtailment penalties generally did not provide the proper incentive to encourage compliance with called interruptions. A sufficiently high enough penalty should be established. To be effective, the penalty charge should be set at a level that is punitive enough that unauthorized use occurs infrequently. It should not give customers the opportunity to choose to take unauthorized gas as an economic decision.

The utilities have the following tariff provisions setting curtailment penalties for their respective interruptible customers:

GMG:

> If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company, customer shall pay, in addition to the appropriate rates above, the higher of (i) $1.00 per CCF, or (ii) an amount equal to any payment Company is required to make to its transporting pipeline, Northern Natural Gas (NNG), as a result of such failure to curtail, interrupt, or restrict service as follows:
>
> If NNG calls an operational flow order, system [overrun] limitation (SOL) or critical day, the additional charge for unauthorized use will be equal to the NNG daily delivery variance charge or critical day charge in effect for such day multiplied by customer's unauthorized use volume. Currently, the charge is $11.30 per CCF. As NNG revises its rate schedules, the Company's rate will be adjusted accordingly. [141]

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139 The Department notes that even though CenterPoint Energy's answer to IR 18 said back-up systems are not required, the small volume firm/interruptible tariff Section V, Page 5 says under *Special Conditions Interruptible Volumes*: 1) Customer must have and maintain adequate standby facilities and have available sufficient fuel supplies to maintain operations during periods of curtailment.

140 The Department notes that NNG's highest cost of demand for the 2013-2014 winter was $15.153/Dth for TF-5 service.

141 Gas Rate Book, Section V, Sheet Nos. 14 and 16.

Great Plains:

If customer fails to curtail or interrupt their use of gas hereunder when requested to do so by the Company, any gas taken shall be billed at the Firm General Gas Service Rate N70 [or S70 for GP South] plus an amount equal to any charges the Company is required to pay to interconnecting pipeline(s) as a result of such failure to curtail or interrupt, or $50.00 per dk of gas used in excess of the volume of gas to which customer was requested to curtail or interrupt, whichever amount is greater.[142]

Interstate Gas:

...the customer shall be subject to a charge of $10.00 for each MMBtu of such excess gas used in addition to the therm charges for gas usage under this rate, plus any pipeline penalties that resulted from the Customer's excess use of gas during the curtailment period.[143]

Rate: Add to the existing interruptible rate, for gas volumes in excess of the daily quantity which the Customer is advised is available under the standard interruptible rate service for such day, a surcharge equal to the difference between the commodity cost as calculated in Interstate's current PGA filing and the highest delivered cost of such gas at the time of delivery.[144]

MERC for Transportation customers:

If customer fails to curtail its use of gas hereunder when requested to do so by Company, customer shall be billed at the transportation charge, plus the cost of gas Company secures for the customer, plus the greater of either the pipeline daily delivery variance charges (see Sheet 6.50) or $20 per dekatherm, whichever is applicable, for gas used in excess of the volumes of gas to which customer is limited.[145]

Penalty For Unauthorized Takes When Service is Interrupted: Applicable rate in Paragraph "4" plus either the charge from pipeline (see Sheet 6.50) or $20.00 per dekatherm so taken, whichever is applicable.[146]

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142 Gas Rate Schedule – MNPUC Volume 2, Section No. 5, Sheet No. 5-45.

143 Gas Tariff, Volume No. 6, Sheet Nos. 4.1 and 5.1.

144 Gas Tariff, Volume No. 6, Sheet No. 6A.

145 Gas Tariff, Sheet No. 6.09.

146 Gas Tariff, Sheet Nos. 5.11, 5.15, 5.21, and 5.25.

MERC for Super Large Volume Service:

> Buyer shall be billed and shall pay $20.00 per dekatherm for unauthorized overrun gas in addition to the rates in Paragraph "3". In addition, should Northern Natural Gas Company call a Critical Day, the penalty for unauthorized takes will be those set out on Sheet No. 6.50.[147]

CenterPoint Energy:

> If a customer fails to discontinue use of gas within one hour of being requested to do so by CenterPoint Energy, the customer will be deemed to have taken Unauthorized Gas. The penalty for unauthorized use of gas will be:
>
> a) For the first occurrence of the gas year: the prevailing delivery charge plus the highest incremental supply cost for the day plus $1.00 per Therm.
> b) For subsequent occurrences: the prevailing delivery charge plus the highest incremental supply cost for the day plus $2.00 per Therm.[148]

Xcel Gas:

During the FYE14, Xcel Gas' curtailment penalty was $1 per therm ($10 per Dth). Xcel stated in its response to IR 18 that:

> The company's financial penalty is not adequate to encourage compliance. For this reason, on June 27, 2014, we filed a petition to modify the interruptible tariffs in Docket No. G002/M-14-540. The petition includes a request to increase the penalty rate to $5 per Therm.

Subsequently, the Commission's October 17, 2014 *Order* adopted and approved the Department's recommendations, including the increase in the penalty charge for unauthorized use of gas from $1 per therm to $5 per therm. The new tariff language is as follows:

> If customer fails to curtail, interrupt, or otherwise restrict (partially or totally) use of gas hereunder when requested to do so by Company, customer shall pay, in addition to the appropriate above rates, the higher of (i) $5.00 per Therm or (ii) an amount equal to any incremental cost incurred by the Company that results from a failure to curtail or interrupt.

147 Gas Tariff, Sheet No. 5.51.

148 Gas Rate Book, Section V, Pages 4, 5 and 6.

> For customers taking service on Company gas distribution systems connected to Northern Natural Gas Company (NNG). If NNG calls an operation flow order, system [overrun] limitation (SOL) or critical day, the additional charge for unauthorized use will be equal to the Northern daily delivery variance charge or critical day charge in effect, as defined in NNG's tariff on Sheet No. 53, for such day multiplied by customer's unauthorized use volume.
>
> For customers taking service on Company gas distribution systems connected to Viking Gas Transmission Company (VGT). If VGT calls an operation flow order, the additional charge for unauthorized use will be equal to the unauthorized overrun charge in VGT's Rate Schedule LMS in effect, as defined in VGT's tariff on Sheet No. 5C, for such day multiplied by customer's unauthorized use volume.[149]

The utilities' penalty tariffs fall into two categories:

- charging non-compliant customers incremental costs PLUS a penalty; or
- charging non-compliant customers incremental costs OR a penalty.

The tariffs for MERC, Interstate Gas, and CenterPoint Energy allow these utilities to charge interruptible customers for any incremental costs plus a penalty, and the tariffs for GMG, Great Plains, and Xcel Gas allow these utilities to charge non-compliant customers for the incremental costs or a penalty, whichever is higher.

At a minimum, firm customers need to be made whole for interruptible customers' non-compliance with curtailments. Ideally, the costs and penalties charged to non-compliant interruptible customers would remove all economic incentive to take unauthorized gas service. The Department used CenterPoint Energy's language, as a starting point that non-compliant customers will be charged delivery charges and pipeline penalties (if applicable), plus the highest incremental cost of gas for the day, plus an additional per-therm penalty. However, the Department would suggest that the penalty for all occurrences of non-compliance be raised to $5.00 per therm, rather than $1.00 or $2.00 as currently stated, as follows:

> If a customer fails to discontinue use of gas when (or within one hour of being) requested to do so, the customer will be deemed to have taken Unauthorized Gas. The penalty for unauthorized use of gas will be: the prevailing delivery charge, plus the highest incremental supply cost for the day, plus $5.00 per therm.

149 Minnesota Gas Rate Book – MPUC No. 2, Section 5, Sheet No. 12

The Department requests that the utilities provide discussion in Reply Comments on this suggested $5.00 per therm penalty and tariff language.

d. MERC's Transportation for Resale Tariff

When reviewing MERC's response to IR 18, the Department noted significant refunds to several customers in May and June 2014. The Department issued Information Request No. 21 asking MERC for a detailed discussion regarding these credits. In its response, MERC explained then unique circumstances for each refund. One refund was for its Transportation-for-Resale customer. MERC stated,

> MERC reversed the penalty on its Transportation-for-Resale customer because MERC thought that customer should be treated as a firm customer. That customer is a gas utility that serves residential customers and may not curtail its customers. That customer is also MERC's sole Transportation-for-Resale customer, and after imposing the penalty, MERC reviewed the Transportation-for-Resale rate schedule. Based on this review, MERC concluded that the Transportation-for-Resale customer was not required to purchase Daily Firm Capacity ("DFC"). As a result of this review and because the customer serves residential customers, MERC determined that the Transportation-for-Resale customer should be treated as a firm customer. On this basis, MERC reversed the penalty. After reversing the penalty, MERC discovered that the Transportation-for-Resale rate schedule does, in fact, require Transportation-for-Resale customers to have firm capacity. To date, MERC's Transportation-for-Resale customer has not changed to firm service. MERC will require this step effective November 1, 2015, if firm capacity is available.

The Department recommends that MERC update its Transportation-for-Resale tariff to clarify that the end-use customers for this service are firm customers and cannot be interrupted. For example, the use of "Daily Firm Capacity" in Section 3.B. implies that this tariff includes interruptible service. In addition, this tariff should specify an entitlement level.

e. Conclusions and Recommendations

While it is unrealistic to expect to eliminate all unauthorized use during called interruptions, the amount of unauthorized use during the 2013-2014 heating season was unacceptable. The Department looks forward to the discussion with the utilities on how to modify the interruptible tariffs to mitigate the issue of unauthorized gas use in the future.

The Department recommends that the Commission require that all utility tariffs, except Interstate Gas, have a provision which gives the utilities the right to revoke interruptible customer class status from habitually non-compliant interruptible customers by discontinuing service or moving the customer to firm service.

The Department requests that each utility provide discussion on the following questions discussed in Section III.F.1.b. Customer Concentration and Habitual Offenders in its Reply Comments:

- What anticipated effects would the above recommended change to tariff language have on the utilities' demand entitlements?
- When should a utility remove a customer from interruptible service? Immediately? The following November 1? A different date?
- What notice, if any, is required from the utility to give to a customer before moving the customer to a different rate class? If none is required, how should notice be given?
- What are the specific triggers for a utility to remove a customer from interruptible service? Unauthorized usage over a pre-determined amount of dekatherms? A percentage of winter sales? Non-compliance with called curtailments more than once?
- How long would a customer be excluded from interruptible service before it could be reinstated into that rate class?
- What amount should be charged to be reinstated and what types of costs would be included in the charge?

The Department also recommends that the Commission require that MERC update its Transportation-for-Resale tariff to clarify that the end-use customers for this service are firm customers and cannot be interrupted.

The Department also requests that the utilities provide discussion in Reply Comments on the Department's suggested $5.00 per therm penalty and related tariff language discussed in section III.F.1.c. Demand Cost of Gas and Curtailment Penalties.

2. *Balancing Penalties*

Balancing penalties are fines imposed by regulated Minnesota utilities on transportation customers who fail to nominate the daily amount of expected gas use within a certain degree of accuracy. For the same reasons cited above for interruptible customers, transportation customers must be held financially accountable if they do not use the gas system in a responsible manner. If a transportation customer fails to nominate correctly, the utility (not the individual transportation customer)[150] 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.

[150] This situation is generally the case except for transportation customers who sign "End-User Balancing Agreements" with the interstate pipeline. In such cases, the interstate pipeline directly monitors gas use and directly bills the transportation customer any imbalance charges.

Table G15 below contains a summary of the revenues generated from balancing penalties imposed on transportation customers and credited to firm sales customers during FYE14.

TABLE G15[151]
FYE14
Revenue from Balancing Penalties

Utility	Balancing Penalty Rev. ($)	Penalty Rev. as a Percent of Total Penalties	Total Gas Costs[152] Incurred ($)	Penalty Rev. as a Percent of Total Costs Incurred
Greater Minnesota	$6,030	0.39%	$6,360,602	0.0948%
Great Plains	$145,882	9.43%	$29,293,442	0.4980%
Interstate Gas	$0	0.00%	$10,119,966	0.0000%
MERC-Consolidated	$15,927	1.03 %	$40,238,905	0.0396%
MERC-NNG	$38,702	2.50%	$191,434,993	0.0202%
CenterPoint Energy	$1,297,975	83.88%	$902,777,336	0.1438%
Xcel Gas	$42,849	2.77%	$479,032,245	0.0089%
MN Total	**$1,547,365**	**100.00%**	**$1,659,257,489**	**0.0933%**

As shown above, the revenue from balancing penalties imposed on transportation customers by gas utilities ranges from $0 reported revenues (Interstate Gas) to $1,297,975 (CenterPoint Energy). The percent of total costs ranges from zero percent (Interstate) to 0.4980 percent (Great Plains). The total amount of balancing penalties was $1,547,365, which is $972,600 greater than last year's amount of $574,756.[153] This increase is primarily related to an increase in balancing penalties on the CenterPoint Energy's system. In addition to the above revenue from balancing penalties, NNG pays an annual Penalty Charge Credit to all shippers on its system. The credits reported as received by each utility for FYE14 were as follows:

Table G15a FYE14 NNG Penalty Charge Credits	
Greater Minnesota	$387
Great Plains	$0
Interstate Gas	$1,085
MERC-Consolidated	$0
MERC-NNG	$41,783
CenterPoint Energy	$97,023
Xcel Gas	$44,073
Total	$184,352

151 The data provided in Table G15 is taken from the response to Department Information Request No. 9.

152 The figures listed in the column entitled "Total Costs Incurred" in Table G15 are taken from the gas utilities' Annual True-Up filings. Total costs incurred include demand and commodity costs.

153 This figure includes the NNG Penalty Charge Credits.

G. PEAK-DAY PIPELINE TRANSPORTATION SOURCES

In its analysis of gas supply peak-day reliability, the Department considered two factors: (1) the various pipeline companies that deliver gas to Minnesota gas utilities, and (2) the number of suppliers currently serving each gas utility (discussed in the next section). Table G16 below shows the variety and contribution of pipelines supplying peak-day firm transportation capacity to Minnesota utilities. The peak-day capacity for FYE14 was 2,546,280 Mcf, which is an increase of approximately 1.07 percent (26,847 Mcf) from FYE13.

TABLE G16[154]
FYE14
Summary of Utilities' Gas Supply Transportation Sources
Total Minnesota Peak Quantity

Pipeline	Peak-Day Quantity (Mcf per day)	Percent of Total
Northern Natural Gas Co.	1,751,482	68.79%
Viking Gas Transmission Co.	178,836	7.02%
Great Lakes Gas Transmission	26,368	1.04%
Other Pipelines	41,961	1.65%
Peak Shaving	547,633	21.51%
MN Total	**2,546,280**	**100.00%**

The percentage of peak-day capacity provided by each of the above sources remains relatively unchanged from the amounts in FYE13. Northern provides by far the greatest amount of peak-day capacity to Minnesota utilities, with approximately 68.79 percent of the total peak-day capacity. Depending on the specific situation of each utility, the number of different pipelines transporting gas to a particular utility for Minnesota ratepayers ranges from one to five. While some utilities may have greater options than others in their ability to decrease costs by choice of pipeline sources, pipeline differentiation does not appear to impact service reliability.

H. VARIETY OF GAS SUPPLIERS

The number of gas suppliers used during the heating season varies by utility, ranging from 0 to 32 for firm supplies and from 2 to 35 for interruptible sources. Table G17 below shows the number of long-term firm, firm spot, and interruptible suppliers used by each utility during the 2013-2014 heating season.

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154 The data provided in Table G16 is taken from the response to Department Information Request No. 4.

TABLE G17[155]
Number of Suppliers

Utility	Firm Long-Term Suppliers	Firm Spot Suppliers	Interruptible Suppliers
Greater Minnesota	0	6	6
Great Plains	2	2	2
Interstate Gas[156]	4	16	0
MERC			
Consolidated	10	10	0
NNG	9	10	0
CenterPoint Energy	32	35	32
Xcel Gas	10	24	0

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

I. CAPACITY RELEASE

Capacity release allows gas utilities with transportation entitlements on a pipeline to relinquish unused and unnecessary capacity for variable periods of time and under various conditions. The Commission typically requires utilities to return to ratepayers all revenues from capacity-release transactions through the annual true-up process.[157] Below is a summary of capacity releases and the associated revenues returned to ratepayers during the true-up period.

155 Table G17 is based on the utilities' responses to Department Information Request No. 4.

156 Interstate Gas does not distinguish between spot and interruptible suppliers.

157 See Docket Nos. G004/M-94-21, G004/M-94-22, G001/M-93-1219, G007/M-94-20, G008/M-93-1233, G008/M-93-1234, G008/M-94-853, G002/M-93-1149, G011/M-95-182, and G012/M-93-1251.

TABLE G18[158]
FYE14
Capacity Release

Utility	Capacity Release (Mcf)	Capacity Release ($)	Revenue Per Mcf ($)	Total Gas[159] Costs Incurred ($)	Revenues as % of Total Gas Costs
Greater Minnesota	75,518	$34,105	$0.4516	$6,360,602	0.5362%
Great Plains	0	$0	$0.0000	$29,293,442	0.0000%
Interstate Gas	228,500	$25,538	$0.1118	$10,119,966	0.2523%
MERC-CON	830,140	$37,037	$0.0446	$40,238,905	0.0920%
MERC-NNG	12,417,992	$1,374,191	$0.1107	$191,434,993	0.7178%
CenterPoint Energy	1,695,545	$60,573	$0.0357	$902,777,336	0.0067%
Xcel Gas	2,562,589	$212,643	$0.0830	$479,032,245	0.0444%
MN Total	**17,810,284**	**$1,744,087**	**$0.0979**	**$1,659,257,489**	**0.1051%**

Table G18 shows the large diversity in Minnesota for capacity-release transactions, capacity portfolios, and individual situations of each gas utility. The revenue from capacity release ranges from $0 for Great Plains to $1,374,191 for MERC-NNG. As a percent of total gas costs, the capacity-release revenues ranged from 0 percent for Great Plains to 0.7178 percent for MERC-NNG. Utilities returned a total of $1,744,087 to ratepayers in the true ups in FYE14 compared to the FYE13 amount of $1,634,153. In addition, the total volumetric capacity-release figures decreased from 25,915,853 Mcf to 17,810,284 Mcf between the FYE13 and FYE14 reporting periods. This decrease in capacity release correlates with Table G10, as actual firm capacity requirement was 78 percent of total capacity on the peak day.

J. ANNUAL AUDITOR REPORTS

All regulated utilities are required by Minnesota Rule 7825.2820 to submit an independent auditor's report by September 1 of each year that evaluates the accounting for automatic adjustments for the prior year. Regarding Commission-ordered audit requirements, beginning with the FYE99 AAA report, the Commission has annually required that the gas utilities meet with their independent auditors prior to the auditors' examinations concerning the companies' AAA reports, to review audit procedures and Minnesota Rule 7825.2820.[160] Additionally, the Commission requires gas utilities to direct their independent auditors to include, as one of their procedures, an examination of any significant variations between purchased volumes (per invoices) and sales volumes per the general ledger sales journal.[161] The Commission also requires all gas utilities to continue to have independent auditors

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158 The data listed in Table G18 is based on the utilities' responses to Department Information Request No. 6.

159 The data listed in the column entitled "Total Cost Incurred" is taken from the gas utilities' AAA filings. Total costs incurred include demand and commodity costs.

160 See Docket Nos. G,E999/AA-98-1130, G,E999/AA-99-1095, G,E999/AA-00-1027, G,E999/AA-01-838, G,E999/AA-02-950, and G,E999/AA-03-1264.

161 See Docket No. G,E999/AA-97-1212.

verify in writing in their AAA reports that the actual amounts included in the true-up calculations agree with the utilities' accounting books and records.[162]

All gas utilities submitted auditor's reports in compliance with Minnesota Rule 7825.2820. The Department reviewed each auditor's report filed and notes that there were no exceptions indicated by the auditors. However, as discussed above, Great Plains and MERC had allocation issues between their PGA systems.[163] Therefore, the Department recommends that the Commission require that Great Plains and MERC request its auditor to include as part of the true-up audit, the allocations between PGA systems.

K. LOST-AND-UNACCOUNTED-FOR GAS

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

Using the formula from the U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration's Form 7100.1-1 to calculate the LUF percentages,[164] the Department developed a comparison of LUF gas by utility. Table G19 below presents the Department's summary of LUF gas percentages for the period July 1 2013 to June 30, 2014 for Minnesota jurisdictional volumes.

162 See Docket No. G,E999/AA-96-940.

163 At this time, Great Plains and MERC are the only gas utilities that have more than one PGA system. Great Plains has a North District and South District. MERC has an NNG system and a Consolidated system. All of the other gas utilities have a single or consolidated PGA system.

164 The formula is as follows: [(purchased gas + produced gas) minus (customer use + utility use + appropriate adjustments)] divided by (purchased gas + produced gas) equals percent unaccounted.

TABLE G19[165]
Lost-and-Unaccounted-For Gas
For FYE14

Utility	LUF Percent
Greater Minnesota	(0.22) %
Great Plains-North	0.58 %
Great Plains-South	1.46%
Interstate Gas	1.10 %
CenterPoint Energy	1.31 %
MERC-Consolidated before correction	(1.15) %
MERC-Consolidated after correction	0.38 %
MERC-NNG before correction	(3.07) %
MERC-NNG after correction	(2.82) %
Xcel Gas	1.30 %
MN Weighted Average before MERC corrected	**0.84%**
MN Weighted Average after MERC corrected	**0.90%**

As shown in Table G19, the LUF gas ranged from a negative 2.82 percent for MERC-NNG after correction to a positive 1.46 percent for Great Plains' South District. The Minnesota weighted average was 0.90 percent after MERC's corrections.

A negative LUF number means that a utility, in effect, "found" gas. As shown in Table G19 above, MERC-NNG continues to report negative lost gas during the reporting period. For FYE14, MERC-NNG had a corrected negative 2.82 percent. In the FYE09 AAA Report, as recommended by the Department, MERC investigated and provided an in-depth discussion of its negative LUF situation that occurred during the 2008-2009 true-up period.[166] Further, in the Commission's November 14, 2013 Order in Docket No. 12-756, the Commission stated the following for the MERC-PNG and MERC-NMU PGA systems:

> The Commission finds that MERC's persistent report of negative lost and unaccounted-for gas may warrant further investigation. If MERC's next [2013] annual automatic adjustment filing again demonstrates that MERC delivered more gas than it buys or manufactured, MERC must file a report with its next annual automatic adjustment filing addressing this matter. MERC should provide a detailed description and calculation explaining why it continues to have a negative amount of lost and unaccounted-for gas, and the role of transportation customers and sales in this pattern.[167]

MERC filed its LUF report with its FYE14 AAA report. MERC stated:

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165 See Attachment G19 for detailed calculations.

166 See MERC's August 30, 2010 *Reply Comments* in Docket No. G999/AA-09-896.

167 Order page, 6.

> MERC performed a thorough investigation of the LUF in the Company's August 30, 2010 Reply Comments in Docket Nos. G999/AA-09-896, G007/AA-09-1038 and G011/AA-09-1039 regarding the 2008-2009 AAA Report. In those Reply Comments, MERC pointed out that the formula used by the Department in monitoring LUF does not include transportation. MERC, however, has a large percentage of transportation volumes that could affect the LUF calculation. In particular, gas can be lost between Town Border Stations (Gate Stations) and End Use Meters the same for transporters as for retail customers. The total system perspective for MERC is an important consideration when making comparisons of LUF between MERC and other utilities. MERC will continue to analyze its LUF reporting to understand the impact of its transport customers. MERC will work with the Department and Commission staff to ensure its AAA LUF reporting methodology is as accurate as possible.

In November of 2014, MERC informed the Department that it was continuing to investigate LUF and that a billing error had been found that would take care of some of the negative LUF. Later in response to Department Information Request No. 23, MERC revised its calculation of LUF gas for the FYE14. MERC stated that it had discovered two errors after submitting its initial response to Department Information Request No. 10:

1. A defective flow meter, owned by Great Lakes Gas Transmission (GLGT) inaccurately measuring the amount of gas supplied to MERC by GLGT at its Grand Rapids town border station. The correction of the metering error resulted in an adjustment of an estimated 171,151 Dth of "unmetered" gas that MERC-CON received during the time period of July 2013 through June 2014; and

2. An incorrect assignment of approximately 350 customers to the MERC-NNG PGA system rather than the MERC-CON PGA system from July 2013 to October 2014.[168] This caused 69,877 Dth of Customer Use Gas to be included in the MERC-NNG LUF calculation and the same amount to be excluded from the MERC-CON LUF calculation.

MERC also stated that "The incorrectly assigned Deer River customer gas cost recovery revenue amounts will be corrected in MERC's 2015 annual true up." [169]

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168 The Department notes that this period extends three months beyond the FYE14 true up period but the difference of removing the customer use from the LUF calculation for the 350 customers during the summer is likely insignificant.

169 The Department discussed the status of the billing adjustments with MERC. At the time, MERC was working with Vertex to calculate corrected bills and compare them to original bills. No corrections had been issued and the total dollar amount of the error was unknown. Further, MERC surmised that the Deer River customers were likely overcharged since MERC-NNG's rates are generally higher than MERC-CON's rates.

The Department notes that the GLGT metering error only pertains to the MERC-CON PGA customers who were all undercharged. Regarding, the Deer River error, the Billing Error Rule (Minn. Stat. 7820.4000) seems to apply. Thus, the Department recommends that MERC respond in Reply Comments with its recovery proposals for the GLGT metering and Deer River errors and whether variances are necessary.

L. REPORTING OF CONTRACTOR MAIN STRIKES AND METER TESTING

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

1. Contractor Main Strikes Reports

Regarding contractor main strikes reports, all of the gas utilities except GMG filed the required information.[170] The Department reviewed the reports. The reports would be more meaningful if the total gas cost charged for main strikes during the period reconciled to the amount in the true up. CenterPoint Energy was the only utility to total the gas costs in its report and provide the allocation of the gas costs credited to the various classes in its true up.[171] Therefore, the Department recommends that the Commission require that all the utilities total the gas costs in its report and also provide the allocation of the gas costs credited to each class in its true up of commodity costs.

GMG responded to the Department's request for a report on its contractor main strikes:

> GMG did not sustain any contractor main strikes subsequent to the date of the Commission's approval [October 11, 2012]; and, therefore, there was nothing to bill or include in the AAA report. In the event that GMG's main line is subjected to contractor strikes in the future, GMG will bill the relevant contractor(s) in accordance with the formula approved by the Commission in January, 2014 and will include the requisite information in a AAA filing.[172]

2. Meter Testing Updates

Regarding meter testing updates, all of the gas utilities except GMG and Great Plains filed the required information with their AAA Reports.

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170 See Great Plains' AAA Report, Exhibit D, Interstate Gas' AAA Report, Attachment A, MERC's AAA Reports, Schedule Q, CenterPoint Energy's AAA Report, Exhibit 9 and Xcel Energy's AAA Report, Attachment G, Schedule 7.

171 CenterPoint Energy's true up, pages 10 and 11.

172 GMG's response to Department Information Request No. 27.

GMG responded to the Department's request for an update on its meter testing:

> Since that time [October 11, 2012], GMG's meter testing program has not changed, so there has not been any update. GMG continues to sample and test 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.[173]

In its AAA Report cover letter, Great Plains stated that it would provide updates regarding meter testing in a separate submittal. Upon prompting from the Department, on February 12, 2015 Great Plains submitted its update on meter testing. Great Plains stated that in 2013, it made several minor modifications to its Gas Meter Testing in Section 7 of Great Plains' Gas Distribution Standards and provided the red-line and final revisions in its Attachment A. Great Plains explained that the revisions did not affect the overall context of the meter testing plan. The Department reviewed the revisions and confirms that the revisions did not affect the overall context of the meter testing plan.

Interstate Gas stated that it "has not made any changes to its Gas Meter Inspection and Testing Program since that filing."[174]

MERC stated:

> MERC has made one change to the timing of its meter testing program that has affected the number of meters tested during the AAA period. During this period MERC tested 876 meters as part of its meter testing program. Of those meters tested 816 (93%) tested between 98% and 102% accurate which is within the range of acceptable accuracy, 42 meters (4%) tested greater than 102% accurate, 14 meters (2%) tested less 98% accurate and 4 meters (less than 1%) had no test due to the meter being damaged. In last year's AAA, MERC reported a total of 2,292 meters tested. The difference in total number of meters tested is attributable to the fact that MERC tested a substantial amount of meters in the first half of 2013. This year, however, we shifted our timing so that our tests for March through July are currently underway. We have made no other modifications to the meter testing program and we expect to test the same number of meters (approximately) in the calendar year 2014 as 2013, but we are not able to provide the results of those tests in this AAA period.[175]

173 GMG's response to Department Information Request No. 28.

174 Interstate Gas' AAA Report, Exhibit Q, page 1.

175 MERC-NNG's AAA Report, page 12 and MERC-Consolidated's AAA Report, page 13.

The Department does not object to MERC's change in the timing of the meter tests. However, the Department recommends that the Commission require that MERC's future meter testing reports provide the meter testing results on a calendar year basis starting with the year 2014.

CenterPoint Energy stated:

> CenterPoint Energy continued its meter testing and management program in 2013. Meter samples and tests are conducted over a two year period and the current interval (2013-2014) is underway; therefore no additional meter lots were given a "final" passing or failing status by the end of 2013. CNP did exchange over 10,700 meters during 2013 from previously identified groups requiring attention; which is ahead of the overall replacement plan. The work plan for 2014 has targeted about 6,500 meters to be exchanged during 2014 from previously identified meter groups requiring attention.[176]

Xcel Gas stated:

> There were changes commencing January 2014 to the test frequency of some rotary gas meters. The rotary meters with a capacity of 11,000 CFH and less are grouped into 8-year periodic test lots; these meters were previously in a 5-year periodic test lot. Rotary meters with a capacity greater than 16,000 CFH are grouped into 4-year periodic test lots; these meters were previously in an annual periodic test lot. The changes were made since the previous test frequency indicated that the meters are performing accurately.[177]

The Department does not object to Xcel Gas' change to the test frequency of some rotary gas meters.

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

M. MINNESOTA GAS UTILITIES' PURCHASING PRACTICES

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

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176 CenterPoint Energy's AAA Report, page 21.

177 Xcel Energy's AAA Report, Attachment G, page 10.

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

- review of the utilities' PGAs and filing of subsequent reports;[178]
- 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.

That said, the Department saw this review as another opportunity to take a critical look at the analysis it provided in previous reports. The following analysis looks different from previous years, but the Department believes that its analysis is concise and provides more value. The previous comparisons between commodity purchases by component were not directly comparable between utilities and years, due to including non-commodity type costs and related volumes with commodity purchases (*e.g.*, hedging, storage[179]), as well as annual changes in weather and the commodity market. Previously, the Department also reported data on the cost and volatility rankings, but generally, the rankings were what could have been expected based on the supply issues (weather events, storage levels, economic conditions, and commodity market dynamics) during that heating season.

Further, purchasing practices differ between utilities based on resources available. CenterPoint Energy, MERC, and Xcel Gas use hedging. Great Plains North does not have access to storage, and GMG procures storage only for balancing purposes. Utilities that have peak shaving facilities are CenterPoint Energy and Xcel Gas.[180] GMG uses outside sources to assist it with gas resource portfolio management.[181] Thus, each gas supply portfolio is unique to the utility.

As discussed in Section I, the weather in FYE14, as well as during the heating season, was significantly colder than normal across the state. Additionally, significant supply issues lead to higher prices in January through March 2014. Further, there were high spikes in gas daily prices in each of these months[182] and a significant drawdown of storage by April 2014.[183] The gas prices in FYE14 were higher than FYE13 and increased during the entire reporting period. At a high level, ranking the annual non-weighted averages of the various types of gas purchase prices creates the following order of prices from lowest to highest for the FYE14: [184]

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178 For example, the PGAs in March 2014 showed a steep increase in the commodity cost for most of the utilities. In April 2014, the Department sent information requests to each of the gas utilities except GMG. The Department reviewed each response and concluded that no action was necessary.

179 For more examples, see the Department's reconciliation of purchases to sales volumes and dollars in Attachment 24 in Docket No. 12-756.

180 Department Information Request No. 12.

181 GMG's AAA Report, page 2.

182 The price range for Ventura for January 28, 2014 was \$30 to \$85 with a midpoint posting of \$53.31/Dth. CenterPoint Energy's Natural Gas Market Overview presented to the Commission on May 29, 2014.

183 According to the U.S Energy Information Administration's Short-Term Energy Outlook, May 2014, the lowest point was approximately 0.8 BCF or less than 40 percent of U.S. storage.

184 The data is taken from the response to Department Information Request No. 5. Hedging costs are included in the cost of monthly index-priced gas for CenterPoint Energy, Xcel Gas, and MERC .

1) Monthly index-priced gas[185] at $4.7750 per Mcf;
2) Monthly spot-market priced gas[186] at $5.3440 per Mcf;
3) Daily index-priced gas[187] at $6.0514 per Mcf;
4) Daily spot-priced gas[188] at $11.3749 per Mcf;

To show the various purchasing approaches, the following table compares the percentages of each type of gas purchase (*i.e.*, monthly index-priced gas, daily index-priced gas, monthly spot-priced gas, daily spot-priced gas) to each utility's total portfolio for the FYE14 heating season.

Table G20[189]
Portfolio Composition for the FYE14 Heating Season
(Components as a Percent of Actual Purchases)

Utility	All Gas Purchases	Index Gas (Monthly)	Index Gas (Daily)	Spot Gas (Monthly)	Spot Gas (Daily)
Great Plains North	100%	57.53%			42.27%
Great Plains South	100%	67.84%			32.16%
Greater Minnesota	100%	62.30%	37.70%		
Interstate Gas	100%	89.75%			10.25%
MERC-CON	100%	78.06%	3.28%		18.66%
MERC-NNG	100%	79.68%	11.13%	4.73%	4.47%
CenterPoint Energy	100%	61.20%	38.52%		0.28%
Xcel Gas	100%	65.56%	19.13%		15.31%

Monthly index-priced gas as a percent of the winter portfolio ranged from a low of approximately 61.20 percent (CenterPoint Energy) to a high of 89.75 percent (Interstate Gas). Of the utilities that purchased daily index-priced gas during the heating season, the percent of the portfolio ranged from a low of 3.28 percent (MERC-Consolidated) to a high of 38.52 percent (CenterPoint Energy). All of the utilities except GMG bought daily spot gas in the winter ranging from a low of 0.28 percent (CenterPoint Energy) to a high of 42.27 percent (Great Plains North). Only MERC-NNG bought 4.73 percent of monthly spot gas during the heating season. In sum, Minnesota gas utilities relied most heavily on monthly

185 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.

186 Monthly spot-priced gas purchases refers to gas purchased on the monthly spot market (*i.e.*, the price at which gas will be purchased under the monthly spot contract depends on the market price of gas for the upcoming month at the time the contract is executed) and delivered to the utility's city gate.

187 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.

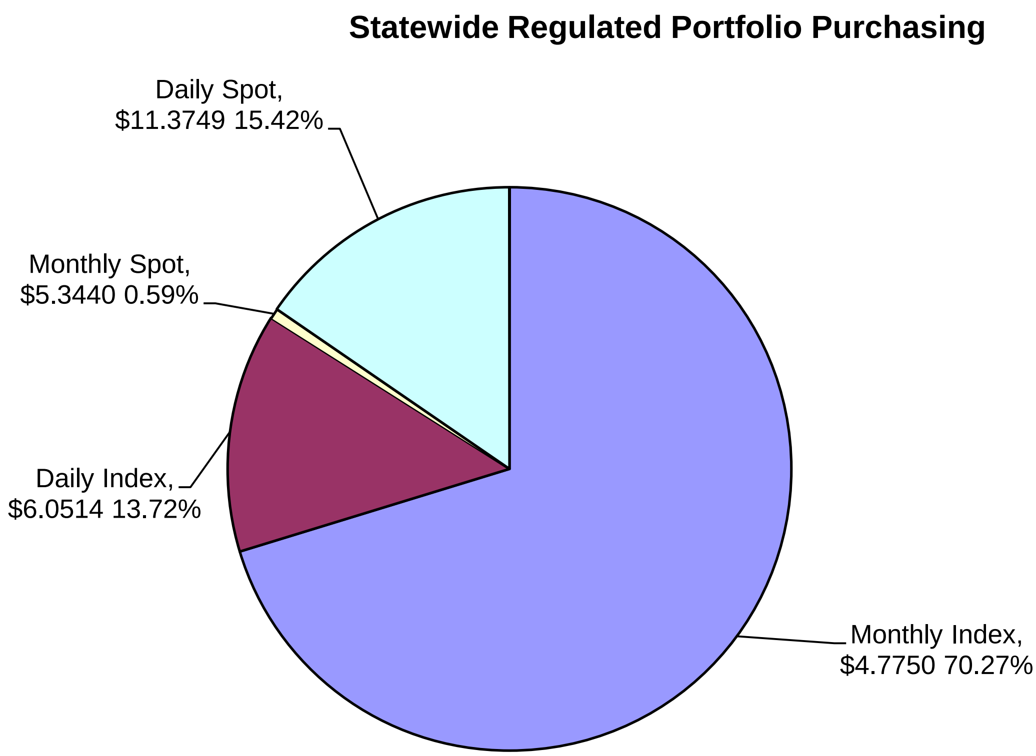
188 Daily spot-priced gas purchases refers to gas purchased on the daily spot market, at market prices under a contract that is in effect for only one day or purchase, and delivered to the utility's city gate.

189 The information for Table G20 can be found in each of the utility's response to Department Information Request No. 5(c).

index-priced gas, daily spot-priced gas, and daily index-priced gas as weather and market conditions fluctuated to extremes.[190]

Using the annual purchase prices and non-weighted average heating season percentages for FYE14, Graph 2 below illustrates the following statewide regulated natural gas utilities' portfolio make-up:

Graph 2



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

Using data from Department Information Request No. 11, the Department compared the non-weighted average FYE14 per-unit storage cost of gas for the individual utilities.[191] Additionally, using data from Department Information Request No. 5(c), the third column shows, by utility, the percentage of storage used, or withdrawn, during the reporting period compared to the utility's total gas portfolio. The results are shown below in Table G21.

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190 Storage gas is not shown in Table G20 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.

191 Both CenterPoint Energy and Xcel Gas confirmed that, although they consider their storage detail to be trade secret, their total storage rate is public information. Further, Xcel Gas confirmed that its storage percentage is public information.

TABLE G21
FYE14
Actual Per Unit Storage Cost and Percentage of Storage[192]

	Storage Costs $/Mcf	Portfolio % Storage[193]
Greater Minnesota[194]	$0.0000	00.00%
Great Plains North	$0.0000	00.00%
Great Plains South	$3.6386	15.38%
Interstate Gas	$3.8753	20.78%
MERC-CON	$3.0989	16.45%
MERC-NNG	$4.2417	36.18%
CenterPoint Energy	$4.2065	21.18%
Xcel Gas	$3.8879	27.65%
MN Weighted Average	**$4.0751**	
MN Non-Weighted Average	**$3.8248**	

Table G21 indicates that the actual storage costs, for utilities that used storage for other than balancing, ranged from a low of $3.0989 per Mcf for MERC-Consolidated to a high of $4.2417 per Mcf for MERC-NNG. The Minnesota non-weighted average cost of storage was $4.0756 per Mcf. Additionally, the percentage of storage gas withdrawn during the winter as part of the utility's total winter volumes ranged from a low of 0.00 percent for Great Plains North to a high of 36.18 percent for MERC-NNG. Thus, 36.18 percent of MERC-NNG's total portfolio for FYE14 was storage gas withdrawn at an average cost of $4.2417 per Mcf.

Certain qualifications should be considered when comparing storage costs. For instance, a trade-off between price and reliability applies to storage supplies. Gas supplies in storage fields are often a step removed from gas-producing fields and gathering facilities, thereby providing a greater reliability of supplies during sustained cold periods that may affect wells in the production fields. While gas injected into storage during the non-heating season generally costs less than gas purchased during the heating season (*e.g.*, in FYE09 heating season prices fell below summer prices), the added cost of using storage facilities and services may result in a higher final per-unit price of the storage gas than gas purchased during the heating season directly from the supplier. However, utilities have more control in using their own storage gas during peak situations. Therefore, the trade-off between price and reliability should be an important consideration in each utility's gas portfolio decisions.

O. MINNESOTA GAS UTILITIES' HEDGING PRACTICES

In its August 11, 2014 *Order Accepting Gas Utilities' Annual Reports and 2012-2013 True-Up Proposals and Setting Further Requirements* in Docket No. 13-600, the Commission

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192 The storage costs listed in this table relate to total storage costs for the entire reporting period, while the portfolio percentages relate solely to those used during the five-month heating season.

193 The Department calculates these percentages based on information provided in response to Information Request Nos. 5 and 11.

194 GMG's storage is primarily used for balancing.

requested that the Department provide a review of hedging practices in its review of future annual automatic adjustment reports. Again, the following analysis looks different from previous years, but the Department believes that its analysis is concise and provides more value by evaluating expectations against actual performance.

Background

The goal of hedging is to use appropriate strategies to minimize the risk of cost increases for any given level of reduced volatility. In a sense, a hedge is an insurance policy that, for a fee, protects utilities (and their ratepayers) against a specific (unfavorable) event occurring during the term of a policy. Hedging can be used to reduce gas price risk by generating a payment in the event that the market price of natural gas moves in an unfavorable (and unpredicted) direction. There are a number of hedging tools/instruments available in the derivative market such as futures contracts, commodity swaps, "costless" collars, and options.[195]

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

Weather and various supply issues play a significant role in the commodity price of natural gas, especially during the heating season of November through March. As previously discussed in Section 1.C. *Natural Gas Prices and Weather*, the 2013-2014 heating season was one of the coldest in recent history. In addition, several other non-weather issues caused interruptions to supply (*e.g.,* well-freeze offs, significant draw-down of storage, and the explosion on a line section of the TransCanada pipeline). As a result, market prices for gas in February and March 2014 were significantly higher than anticipated.

In this type of market environment, the Department would anticipate that CPE, MERC, and Xcel Gas would experience cost savings and/or gains on the hedge portion of their purchase portfolios. The following discussion reviews the performance of each utility's hedging program against this expectation.

MERC

MERC utilizes a 40%/30%/30% hedging strategy to mitigate price volatility and provide reasonably priced natural gas; 40 percent of normal winter requirements purchased at fixed price, 30 percent purchased using financial derivatives, and 30 percent purchased at market rates.[196] This strategy is not one to guarantee the lowest priced gas but a strategy to mitigate price volatility, provide reasonably priced natural gas and ensure reliability.[197]

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

196 MERC's *2014 Annual Automatic Adjustment Report*, page 2.

197 *Id.*, page 3.

In Docket No. G007,011/M-13-207, MERC was granted an extension to its variance to recover the costs associated with certain financial instruments through the PGA through June 30, 2015. For details on previous variance dockets and compliance requirements, please see Section II.D.3 *Compliance and/or Supplemental Reporting Requirements*.

For the 2013-2014 heating season, MERC fulfilled its 40 percent of fixed price requirements through a combination of pipeline storage and financial Futures, 30 percent of financial derivatives requirements through financial Call Options backed physically by FOM index supply, and 30 percent of its market rate requirements at first of month (FOM) index and in the spot market.[198] The financial gain to ratepayers from MERC-NNG's and MERC-Consolidated's Futures and Call Options was $2,762,755.[199] Although MERC did not quantify it, there was almost certainly additional cost savings as a result of the requirements contracted through pipeline storage.

MERC's hedges provided a financial gain due to the high prices experienced in February and March 2014, as the Department expected. The Department concludes that MERC accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

<u>CenterPoint Energy</u>

CenterPoint Energy's policy is to provide price stabilization for a portion of its winter supply through hedge gas purchases and storage gas, to provide protection against volatile gas prices. The level of stabilization to be achieved is re-determined each year based on analysis that incorporates regulatory guidelines (as to volumes and costs), winter price projections, and available portfolio assets.[200]

In Docket No. G008/M-12-166, CenterPoint Energy was granted an extension to its variance to recover the costs associated with certain financial instruments through the PGA through June 30, 2016. For details on previous variance dockets and compliance requirements, please see Section II.E.2 *Compliance and/or Supplemental Reporting Requirements*.

Regarding its hedging strategy for the 2013-2014 winter season, CPE stated,[201]

> Storage volumes (pipeline and on-system combined) represented 17.6% of the winter system supplies. Physical base load gas purchases containing price protections were made over several months during the summer using multiple [Request for Proposals] RFP's. CenterPoint Energy used 9.6 BCF of purchased gas (8.6% of system supplies) with call and put options in combination to form collars to allow the price paid by CenterPoint Energy to float down (participate downward) with the market when prices dropped. CenterPoint Energy also

198 *Id.*, page 2.

199 MERC's *2014 Annual Automatic Adjustment Report*, Schedule L.

200 CenterPoint Energy's *Annual Automatic Adjustment Report*, page 2.

201 *Id.*, page 5.

> used 8.3 Bcf (7.4% of purchased gas with call options alone to further stabilize supply prices. Those volumes total 17.9 Bcf of total supply and, when combined with the 19.5 Bcf of storage volumes (including 1.4 of Underground storage classified as peaking volumes), provide stabilized prices for 35% of winter gas supplies.

According to CenterPoint Energy, the price of its hedged purchases resulted in an approximate $20 million reduction to the annual costs that would have occurred had CPE purchased all gas at first of month (FOM) indices. Hedged gas purchases saved approximately $0.18 per dekatherm to CenterPoint Energy's customer's costs during the winter period.[202]

In its response to the Department's Information Request No. 15, CenterPoint Energy stated that the only significant change in its hedging program from the previous year was the level of purchases hedge decreased from 21.0 Bcf last year to 17.9 Bcf this year. CPE further stated that this reduction in volumes hedged was made due to the low volatility in market prices expected for the 2013-2014 winter season.

CenterPoint Energy's hedges provided a financial gain due to the high prices experienced in February and March 2014, as the Department expected. The Department concludes that CenterPoint Energy accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

<u>Xcel Gas</u>

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.[203] 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.[204]

In Docket No. G002/M-12-519 (Docket 12-519), Xcel Gas was granted an extension to its variance to recover the costs associated with certain financial instruments through the Purchased Gas Adjustment (PGA) through June 30, 2016. For details on previous variance dockets and compliance requirements, please see Section II.F.2 *Compliance and/or Supplemental Reporting Requirements*.

However, Xcel Gas suspended its hedging activity when its prior variance authorization ended on June 30, 2012 because the Commission's Order in Docket 12-519 was not issued until September 23, 2013, well into the summer season when Xcel Gas would have normally entered into hedging transactions for the upcoming 2013-2014 heating season. Upon receiving written notice of the order, Xcel Gas implemented the portion of the 2013-2014

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202 *Id.*, page 6.

203 Xcel Gas' *Annual Automatic Adjustment of Charges Report*, Attachment A, Schedule 5, page 2.

204 *Id.*, page 3.

hedging program that was planned to be executed in the months of September and October of 2013.[205]

Regarding the performance of its hedging strategy for the 2013-2014 winter season, Xcel Gas reported that it hedged 4,530,000 dekatherms (Dth) on which Xcel Gas gained approximately $8 million.[206] Xcel Gas used all call options to execute its hedges, but was also authorized to use costless collars.[207] Typically, Xcel Gas' goal is to hedge approximately 50 percent of normal heating season requirements, approximately 25.5 percent through storage, and the remaining 24.5 percent through financial instruments.[208] Due to the timing of the Commission's Order in Docket 12-519, Xcel Gas was only able to hedge about a third of the typical volume for the 2013-2014 heating season.[209]

Xcel Gas' hedges provided a financial gain due to the high prices experienced in February and March 2014, as the Department expected. The Department concludes that Xcel Gas accomplished its intended purpose of providing reasonable price protection on a portion of its winter gas supplies, based on the information the company had at the time it executed its hedges.

Conclusion and recommendations

As shown above, each of the utilities experienced gains and/or cost savings due to hedging during FYE14. While this is a benefit to ratepayers, it is important to remember that the natural gas purchases covered by hedges were only a portion of the total winter requirements purchased. The ultimate goal of hedging is to reduce price volatility on a percentage of the utilities' purchase portfolios, not to speculate or make money on commodity prices.

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

IV. SUMMARY OF THE DEPARTMENT'S RECOMMENDATIONS

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

1. The Department recommends that the Commission accept the FYE14 annual reports as filed by the gas utilities as being complete as to Minnesota Rules 7825.2390 through 7825.2920.

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[205] Xcel Gas' *Annual Automatic Adjustment of Charges Report*, Attachment G, page 3.

[206] *Id.*, page 4.

[207] *Id.*, pages 7-8.

[208] Xcel Gas' *Annual Automatic Adjustment of Charges Report*, Attachment A, Schedule 5, page 3.

[209] Xcel Gas' *Annual Automatic Adjustment of Charges Report*, Attachment G, page 4.

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.

3. The Department recommends that the Commission require that all the utilities total the gas costs in its Contractor Main Strikes Report and also provide the allocation of the gas costs credited to each class in its true up of commodity costs.

4. The Department recommends that all utility tariffs, except Interstate Gas, have a provision which gives the utilities the right to revoke interruptible customer class status from habitually non-compliant interruptible customers by discontinuing service or moving the customer to firm service.

The Department also recommends that the Commission require MERC to update its Transportation-for-Resale tariff to clarify that the end-use customers for this service are firm customers and cannot be interrupted.

The Department requests that each utility provide discussion on the following questions:

- What anticipated effects would the above recommended change to tariff language have on the utilities' demand entitlements?
- When should a utility remove a customer from interruptible service? Immediately? The following November 1? A different date?
- What notice, if any, is required from the utility to give to a customer before moving the customer to a different rate class? If none is required, how should notice be given?
- What are the specific triggers for a utility to remove a customer from interruptible service? Unauthorized usage over a pre-determined amount of dekatherms? A percentage of winter sales? Non-compliance with called curtailments more than once?
- How long would a customer be excluded from interruptible service before it could be reinstated into that rate class?
- What amount should be charged to be reinstated and what types of costs would be included in the charge?

The Department also requests that the utilities provide discussion in Reply Comments on the suggested $5.00 per therm penalty and tariff language.

4. <u>Greater Minnesota</u>

The Department recommends that the Commission:

- accept GMG's FYE14 true-up as filed in Docket No. G001/AA-14-728; and
- allow GMG to implement its true-ups, as shown in DOC Attachment G5 of the *AAA Report*.

5. *Great Plains*

The Department recommends that the Commission:

- accept Great Plains' FYE14 true-ups, Docket No. G004/AA-14-749;
- allow Great Plains to implement its true-ups, as shown in DOC Attachments G6a and G6b of the *AAA Report*;
- describe and report each of the FYE14 corrections as a separate line item to the beginning balance of the demand cost of gas in its September 1, 2015 true-up; and
- require Great Plains to request that its auditor to include as part of the true-up audit, the allocations between PGA systems.

6. *Interstate Gas*

The Department recommends that the Commission:

- accept Interstate Gas' true-up filing in Docket No. G001/AA-14-742; and
- allow Interstate Gas to implement its true-up, as shown in Department Attachment G7 of the *AAA Report*.

7. *MERC*

The Department recommends that the Commission:

- accept MERC- NNG's true-up filing in Docket No. G011/AA-14-755;
- allow MERC- NNG to implement its true-up, as shown in Department Attachment G8 of the *AAA Report;*
- accept MERC- Consolidated's true-up filing in Docket No. G011/AA-14-754;
- allow MERC- Consolidated to implement its true-up, as shown in Department Attachment G9 of the *AAA Report*;
- require MERC to request that its auditor to include as part of the true-up audit, the allocations between PGA systems; and
- require that MERC's future meter testing reports provide the meter testing results on a calendar year basis starting with the year 2014.

The Department also recommends that MERC respond in Reply Comments with its recovery proposals for the GLGT metering and Deer River errors and whether variances are necessary.

8. *CenterPoint Energy*

The Department recommends that the Commission:

- accept CenterPoint Energy's FYE14 true up, Docket No. G008/AA-14-752; and
- allow CenterPoint Energy to implement its true up, as shown in Department Attachment G10 of the *AAA Report*.

9. *Xcel Gas*

The Department recommends that the Commission:

- accept Xcel Gas' FYE14 true-up, Docket No. G002/AA-14-736; and
- allow Xcel Gas to implement its true-up, as shown in Department Attachment G11 of the *AAA Report*.

The Department also recommends that in its Reply Comments, Xcel Gas should request a variance for the five occasions where Xcel Gas continued to use the program during 2013-2014 after the expiration of the original variance.

RECORDED UNWEIGHTED HEATING DEGREE DAYS

Source: U of M Monthly Heating & Cooling Summary Tables
http://www.climate.umn.edu/cawap/eddsum/eddsum.asp

ANNUAL DATA

Weather Station	Normals 1971-2000	Normals 1981-2010	SEASON 2009-2010	SEASON 2010-2011	SEASON 2011-2012	SEASON 2012-2013	SEASON 2013-2014	**2013-2014 vs. Normal (71-00)**	**2013-2014 vs. Normal (81-10)**
DULUTH	9,709	9,444	8,540	9,514	7,635	9,366	10,342	**6.52%**	**9.51%**
INTERNATIONAL FALLS	10,216	10,221	9,483	10,303	8,424	10,713	11,511	**12.68%**	**12.62%**
FARGO, ND	9,019	8,802	8,314	9,311	6,840	9,403	9,679	**7.32%**	**9.96%**
ST CLOUD	8,744	8,532	7,904	8,716	6,744	8,872	9,524	**8.92%**	**11.63%**
MPLS/ST PAUL	7,805	7,580	7,007	7,708	5,924	7,708	8,597	**10.15%**	**13.42%**
ROCHESTER	8,150	7,722	7,516	7,927	6,066	7,825	8,917	**9.41%**	**15.48%**
SIOUX FALLS, SD	7,683	7,706	7,690	8,057	6,058	7,884	8,320	**8.29%**	**7.97%**

RECORDED UNWEIGHTED HEATING DEGREE DAYS

November 1--March 31

Weather Station	Normals 1971-2000	Normals 1981-2010	SEASON 2009-2010	SEASON 2010-2011	SEASON 2011-2012	SEASON 2012-2013	SEASON 2013-2014	**2013-2014 vs. Normal (71-00)**	**2013-2014 vs. Normal (81-10)**
DULUTH	7,169	6,952	7,097	7,097	5,716	6,822	8,028	**11.98%**	**15.48%**
INTERNATIONAL FALLS	7,728	7,589	6,992	7,776	6,165	7,747	8,869	**14.76%**	**16.87%**
FARGO, ND	7,145	7,589	6,683	7,545	5,534	7,226	7,849	**9.85%**	**3.43%**
ST CLOUD	6,853	6,665	6,251	7,005	5,340	6,731	7,724	**12.71%**	**15.89%**
MPLS/ST PAUL	6,295	6,108	5,729	6,399	4,864	6,040	7,117	**13.06%**	**16.52%**
ROCHESTER	6,437	6,136	6,003	6,484	4,862	6,052	7,297	**13.36%**	**18.92%**
SIOUX FALLS, SD	6,157	6,105	6,161	6,538	4,882	6,037	6,813	**10.65%**	**11.60%**

RECORDED UNWEIGHTED HEATING DEGREE DAYS

Source: U of M Monthly Heating & Cooling Summary Tables http://www.climate.umn.edu/cawap/eddsum/eddsum.asp

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	DULUTH	July	67	63	47	-29.85%	-25.40%
		August	100	86	27	-73.00%	-68.60%
		September	328	298	168	-48.78%	-43.62%
		October	662	678	610	-7.85%	-10.03%
		November	1,120	1,088	1,105	-1.34%	1.56%
		December	1,599	1,556	1,866	16.70%	19.92%
		January	1,775	1,699	1,955	10.14%	15.07%
		February	1,435	1,399	1,663	15.89%	18.87%
		March	1,240	1,210	1,439	16.05%	18.93%
		April	788	762	886	12.44%	16.27%
		May	413	426	414	0.24%	-2.82%
		June	182	179	162	-10.99%	-9.50%
	TOTALS		9,709	9,444	10,342		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	INTERNATIONAL FALLS	July	52	70	85	63.46%	21.43%
		August	96	111	135	40.63%	21.62%
		September	354	353	222	-37.29%	-37.11%
		October	712	743	726	1.97%	-2.29%
		November	1,206	1,184	1,190	-1.33%	0.51%
		December	1,751	1,714	2,137	22.04%	24.68%
		January	1,942	1,878	2,120	9.17%	12.89%
		February	1,540	1,530	1,816	17.92%	18.69%
		March	1,289	1,283	1,606	24.59%	25.18%
		April	767	772	907	18.25%	17.49%
		May	370	419	438	18.38%	4.53%
		June	138	164	129	-6.52%	-21.34%
	TOTALS		10,217	10,221	11,511		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	MOORHEAD	July	16	16	17	6.25%	6.25%
	In FYE14, changed from Fargo, ND to	August	34	34	17	-50.00%	-50.00%
	Moorhead since Moorhead is reported	September	239	220	91	-61.92%	-58.64%
	on U of M tables whereas Fargo	October	603	606	619	2.65%	2.15%
	is not reported there.	November	1,131	1,086	1,097	-3.01%	1.01%
		December	1,609	1,578	1,882	16.97%	19.26%
		January	1,802	1,728	1,869	3.72%	8.16%
		February	1,435	1,410	1,685	17.42%	19.50%
		March	1,168	1,152	1,316	12.67%	14.24%
		April	646	626	733	13.47%	17.09%
		May	265	273	323	21.89%	18.32%
		June	71	73	30	-57.75%	-58.90%
	TOTALS		9,019	8,802	9,679		

RECORDED UNWEIGHTED HEATING DEGREE DAYS

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	ST CLOUD	July	18	17	26	44.44%	52.94%
		August	46	41	23	-50.00%	-43.90%
		September	247	228	129	-47.77%	-43.42%
		October	593	599	614	3.54%	2.50%
		November	1,071	1,040	1,081	0.93%	3.94%
		December	1,557	1,522	1,815	16.57%	19.25%
		January	1,735	1,655	1,862	7.32%	12.51%
		February	1,372	1,344	1,659	20.92%	23.44%
		March	1,118	1,104	1,307	16.91%	18.39%
		April	630	617	716	13.65%	16.05%
		May	278	287	266	-4.32%	-7.32%
		June	79	78	26	-67.09%	-66.67%
	TOTALS		8,744	8,532	9,524		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	MPLS/ST PAUL	July	6	5	8	33.33%	60.00%
		August	17	14	-	-100.00%	-100.00%
		September	172	154	58	-66.28%	-62.34%
		October	504	507	487	-3.37%	-3.94%
		November	971	939	948	-2.37%	0.96%
		December	1,433	1,404	1,622	13.19%	15.53%
		January	1,608	1,531	1,762	9.58%	15.09%
		February	1,266	1,236	1,568	23.85%	26.86%
		March	1,017	998	1,217	19.67%	21.94%
		April	552	530	662	19.93%	24.91%
		May	215	218	244	13.49%	11.93%
		June	43	44	21	-51.16%	-52.27%
	TOTALS		7,804	7,580	8,597		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	ROCHESTER	July	14	11	23	64.29%	109.09%
		August	34	27	11	-67.65%	-59.26%
		September	205	177	120	-41.46%	-32.20%
		October	541	521	529	-2.22%	1.54%
		November	994	936	1,010	1.61%	7.91%
		December	1,460	1,406	1,601	9.66%	13.87%
		January	1,632	1,530	1,803	10.48%	17.84%
		February	1,301	1,253	1,628	25.13%	29.93%
		March	1,050	1,011	1,255	19.52%	24.13%
		April	597	553	675	13.07%	22.06%
		May	262	245	251	-4.20%	2.45%
		June	60	52	11	-81.67%	-78.85%
	TOTALS		8,150	7,722	8,917		

Base 65	Weather Station:	MONTHLY DATA Month	Normals 1971-2000	Normals 1981-2010	REPORTING PERIOD 2013-2014	2013-2014 vs. Normal (71-00)	2013-2014 vs. Normal (81-10)
	SIOUX FALLS, SD	July	7	8	19	171.43%	137.50%
		August	19	23	15	-21.05%	-34.78%
		September	170	173	66	-61.18%	-61.85%
		October	509	536	535	5.11%	-0.19%
		November	985	972	986	0.10%	1.44%
		December	1,423	1,421	1,647	15.74%	15.90%
		January	1,554	1,499	1,596	2.70%	6.47%
		February	1,222	1,218	1,483	21.36%	21.76%
		March	973	995	1,101	13.16%	10.65%
		April	551	562	570	3.45%	1.42%
		May	224	248	270	20.54%	8.87%
		June	45	51	32	-28.89%	-37.25%
	TOTALS		7,682	7,706	8,320		

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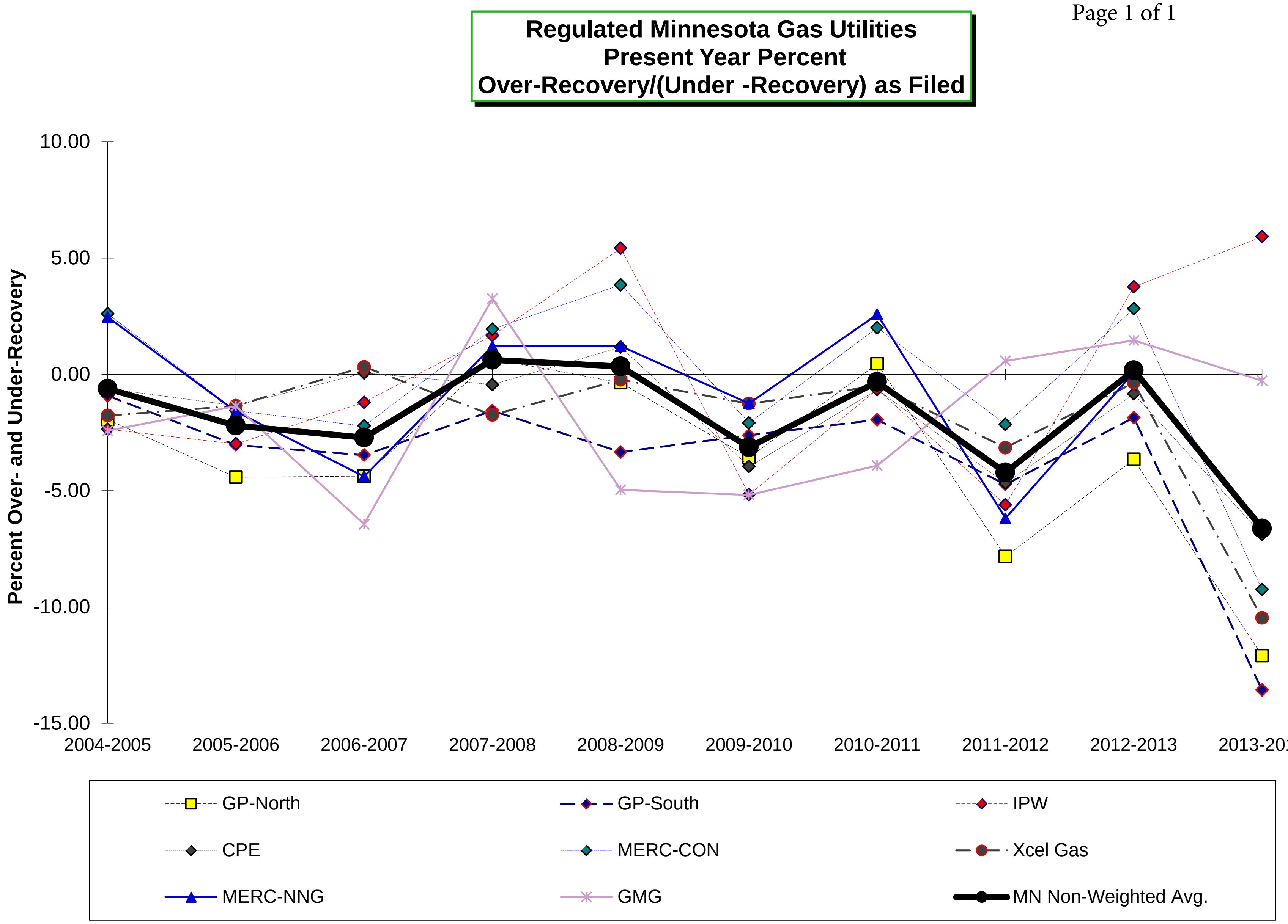

Prepared by the Minnesota Department of Commerce

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.

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 "net" gas cost is \$5.60 per MMBtu, which was the locked in price.

TERMS AND ACRONYMS	*DEFINITION*
	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 No.	Great Plains So.	GMG	Interstate	MERC NNG	MERC-CON	Xcel Gas
NNG TF-12	D		D	D	D	D	D	D
NNG TF-5	D		D	D	D	D	D	D
NNG TFX	D	D	D	D		D	D	D
Viking FT-A	D	D	D				D	D
Great Lakes FT							D	D
ANR FTS-1								D
WBI FT								D
Balancing, Storage, Reservation Fees								
Balancing SMS, LMS **2/**	C	A	A	C	D	C	C	C
NNG storage FDD			C		D	D **1/**	D **1/**	D
NGPL storage	A							
Tenaska storage	A							
Niska storage							D	
ANRP storage								D
Other supplier or producer reservation fees	A				C			

D=Demand cost
A=Costs are allocated between demand and commodity 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 credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented.

Greater Minnesota Gas, Inc.
2013-2014 True Up
Docket No. G022/AA-14-728
As Filed on August 28, 2014

Ten Year Summary of Gas-Cost Recovery

Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
2004-2005	-2.42%	
2005-2006	-1.37%	
2006-2007	-6.44%	
2007-2008	3.25%	
2008-2009	-4.96%	
2009-2010	-5.18%	
2010-2011	-3.92%	
2011-2012	0.58%	
2012-2013	1.46%	
2013-2014	**-0.27%**	**-0.43%**
10 Year Average	-1.93%	

Recovery By Class

	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)	(5) PREVIOUS TRUE-UP OVER/(UNDER) ENDING BALANCE
FIRM	$5,800,693	$5,831,967	($31,274)	**-0.54%**	($3,088)
AGRICULTURAL - INTERRUPTIBLE	$284,367	$277,332	$7,035	**2.54%**	($3,173)
GENERAL - INTERRUPTIBLE	$258,165	$251,303	$6,862	**2.73%**	($4,015)
TOTAL	**$6,343,225**	**$6,360,602**	**($17,377)**	**-0.27%**	**($10,276)**

	(6) (3)+(5) CUMULATIVE OVER/(UNDER) BALANCE	(7) (6)/(2) CUMULATIVE %	(8) Estimated Sales (Mcf)	(9) (6)/(8) True Up (Refund)/Collection
FIRM	($34,362)	**-0.59%**	943,390	**$0.0364**
AGRICULTURAL - INTERRUPTIBLE	$3,862	**1.39%**	39,700	**($0.0973)**
GENERAL - INTERRUPTIBLE	$2,847	**1.13%**	89,285	**($0.0319)**
TOTAL	**($27,653)**	**-0.43%**	**1,072,375**	

Greater Minnesota Gas, Inc.
2013-2014 True Up
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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	$429,592	$361,752	$67,840	18.75%
COMMODITY COST	$2,892,003	$3,036,590	($144,587)	-4.76%
TOTAL	$3,321,595	$3,398,342	($76,747)	-2.26%
COMMERCIAL - FIRM				
DEMAND COST	$13,715	$11,366	$2,349	20.67%
COMMODITY COST	$93,710	$96,764	($3,054)	-3.16%
TOTAL	$107,425	$108,130	($705)	-0.65%
INDUSTRIAL - FIRM				
DEMAND COST	$274,452	$231,788	$42,664	18.41%
COMMODITY COST	$1,914,979	$1,908,920	$6,059	0.32%
TOTAL	$2,189,431	$2,140,708	$48,723	2.28%
FLEX RATE - FIRM				
DEMAND COST	$22,959	$20,409	$2,550	12.49%
COMMODITY COST	$159,283	$164,378	($5,095)	-3.10%
TOTAL	$182,242	$184,787	($2,545)	-1.38%
AG. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$284,367	$277,332	$7,035	2.54%
TOTAL	$284,367	$277,332	$7,035	2.54%
IND. - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$115,933	$121,107	($5,174)	-4.27%
TOTAL	$115,933	$121,107	($5,174)	-4.27%
FLEX RATE - INTERRUPTIBLE				
DEMAND COST	$0	$0	$0	0.00%
COMMODITY COST	$142,232	$130,196	$12,036	9.24%
TOTAL	$142,232	$130,196	$12,036	9.24%

Greater Minnesota Gas, Inc.
2013-2014 True Up
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RECOVERY BY COMPONENT	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)
DEMAND COST:				
Residential - Firm	$429,592	$361,752	$67,840	18.75%
Commercial - Firm	$13,715	$11,366	$2,349	20.67%
Industrial - Firm	$274,452	$231,788	$42,664	18.41%
Flexible Rate - Firm	$22,959	$20,409	$2,550	12.49%
Agricultural - Interruptible	$0	$0	$0	0.00%
Industrial - Interruptible	$0	$0	$0	0.00%
Flexible Rate - Interruptible	$0	$0	$0	0.00%
TOTAL	$740,718	$625,315	$115,403	18.46%
COMMODITY COSTS:				
Residential - Firm	$2,892,003	$3,036,590	($144,587)	-4.76%
Commercial - Firm	$93,710	$96,764	($3,054)	-3.16%
Industrial - Firm	$1,914,979	$1,908,920	$6,059	0.32%
Flexible Rate - Firm	$159,283	$164,378	($5,095)	-3.10%
Agricultural - Interruptible	$284,367	$277,332	$7,035	2.54%
Industrial - Interruptible	$115,933	$121,107	($5,174)	-4.27%
Flexible Rate - Interruptible	$142,232	$130,196	$12,036	9.24%
TOTAL	$5,602,507	$5,735,287	($132,780)	-2.32%
DETAIL OF DEMAND RECOVERY				
Viking Zone 1	$104,668	$74,231	$30,437	41.00%
TFX-5	$543,141	$487,472	$55,669	11.42%
TFX- 7	$68,024	$64,762	$3,262	5.04%
TFX - 12	$21,973	$27,723	($5,750)	-20.74%
TF Capacity Release	$0	($34,105)	$34,105	-100.00%
SMS Demand	$2,911	$5,232	($2,321)	-44.36%
TOTAL	$740,717	$625,315	$115,402	18.46%

Great Plains Natural Gas North District
2013-2014 True-Up
Docket No. G004/AA-14-749
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Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
GP-North	2004-2005	-1.94%	
GP-North	2005-2006	-4.42%	
GP-North	2006-2007	-4.37%	
GP-North	2007-2008	0.67%	
GP-North	2008-2009	-0.36%	
GP-North	2009-2010	-3.57%	
GP-North	2010-2011	0.45%	
GP-North	2011-2012	-7.83%	
GP-North	2012-2013	-3.66%	
GP-North	2013-2014	**-12.09%**	**-11.48%**
	10-Year Average	-3.71%	

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	$9,021,783	$10,357,111	($1,335,328)	**-12.89%**	($446,947)
INTERRUPTIBLE	$3,178,717	$3,521,541	($342,824)	**-9.74%**	$75,875
Total	**$12,200,500**	**$13,878,652**	**($1,678,152)**	**-12.09%**	**($371,072)**

	(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	$554,299	($1,227,976)	**-11.86%**	1,124,200	**$1.0923**
INTERRUPTIBLE	($97,816)	($364,765)	**-10.36%**	496,700	**$0.7344**
Total	**$456,483**	**($1,592,741)**	**-11.48%**		

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Detail of Current Costs by Class	(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)
FIRM				
Viking				
FT-A	$301,869	$262,845	$39,024	14.85%
FT-A (Zone 1-1; Zone 1-2)	$87,123	$93,246	($6,123)	-6.57%
Seasonal FT-A Reservation Charge	$34,169	$29,962	$4,207	14.04%
TFX Seasonal	$139,054	$121,977	$17,077	14.00%
TFX Winter	$904,235	$855,038	$49,197	5.75%
TFX Summer	$474,715	$347,800	$126,915	36.49%
LMS Demand	$19,072	$12,219	$6,853	56.08%
Adjustments to Firm Demand	$0	($80,537)	$80,537	-100.00%
Total Demand	$1,960,237	$1,642,550	$317,687	19.34%
Commodity Cost	$7,061,546	$8,714,561	($1,653,015)	-18.97%
TOTAL	$9,021,783	$10,357,111	($1,335,328)	-12.89%
INTERRUPTIBLE				
Commodity Cost	$3,169,296	$3,512,939	($343,643)	-9.78%
LMS Demand	$9,421	$8,602	$819	9.52%
TOTAL	$3,178,717	$3,521,541	($342,824)	-9.74%

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Recovery by Class		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
FIRM					
	Demand	$1,960,237	$1,642,550	$317,687	19.34%
	Commodity	$7,061,546	$8,714,561	($1,653,015)	-18.97%
	Total	$9,021,783	$10,357,111	($1,335,328)	-12.89%
INTERRUPTIBLE					
	LMS Demand	$9,421	$8,602	$819	9.52%
	Commodity	$3,169,296	$3,512,939	($343,643)	-9.78%
	Total	$3,178,717	$3,521,541	($342,824)	-9.74%

Recovery by Component		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
Demand					
	Firm	$1,960,237	$1,642,550	$317,687	19.34%
	Total	$1,960,237	$1,642,550	$317,687	19.34%
Commodity					
	Firm	$7,061,546	$8,714,561	($1,653,015)	-18.97%
	Interruptible LMS	$9,421	$8,602	$819	9.52%
	Interruptible	$3,169,296	$3,512,939	($343,643)	-9.78%
	Total	$10,240,263	$12,236,102	($1,995,839)	-16.31%

Great Plains Natural Gas South District
2013-2014 True-Up
Docket No. G004/AA-14-749
As Filed by Great Plains on August 29, 2014

Ten Year Summary of Gas Cost Recovery:

	Year Ended 6/30	Present Year Percent Over (Under) Recovery	Cumulative Percent Over (Under) Recovery
GP-South	2004-2005	-0.92%	
GP-South	2005-2006	-3.03%	
GP-South	2006-2007	-3.47%	
GP-South	2007-2008	-1.56%	
GP-South	2008-2009	-3.34%	
GP-South	2009-2010	-2.62%	
GP-South	2010-2011	-1.95%	
GP-South	2011-2012	-4.73%	
GP-South	2012-2013	-1.86%	
GP-South	2013-2014	**-13.57%**	**-12.97%**
	10-Year Average	-3.71%	

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	$9,152,022	$10,634,316	($1,482,294)	**-13.94%**	($27,672)
Small Vol. Interrupt.	$1,743,832	$2,028,590	($284,758)	**-14.04%**	($57,005)
Large Vol. Interrupt.	$2,426,942	$2,751,884	($324,942)	**-11.81%**	($112,621)
Total	**$13,322,796**	**$15,414,790**	**($2,091,994)**	**-13.57%**	**($197,298)**

	(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	$84,331	($1,425,635)	**-13.41%**	1,493,400	**$0.9546**
Small Vol. Interrupt.	$77,749	($264,014)	**-13.01%**	248,900	**$1.0607**
Large Vol. Interrupt.	$128,124	($309,439)	**-11.24%**	648,100	**$0.4775**
Total	**$290,204**	**($1,999,088)**	**-12.97%**		

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	(1)	(2)	(3) (1)-(2)	(4) (3)/(2)
Detail of Current Costs by Class			PRESENT YEAR	PRESENT YEAR
			OVER/(UNDER)	OVER/(UNDER)
FIRM	COST RECOVERY	COST INCURRED	RECOVERY ($)	RECOVERY (%)
Northern				
TF12 Base	$541,655	$483,623	$58,032	12.00%
TF12 Variable	$360,241	$288,706	$71,535	24.78%
TF5 (November - March)	$317,370	$258,359	$59,011	22.84%
TFX	$437,509	$356,096	$81,413	22.86%
FT-A Viking	$163,141	$113,050	$50,091	44.31%
SMS	$44,696	$34,092	$10,604	31.10%
FDD-1 Reservation	$117,247	$102,247	$15,000	14.67%
FDD-1 Demand Charges	$65,113	$27,629	$37,484	135.67%
Propane Peaking Facilities Credit	($126,404)	($126,404)	$0	0.00%
Adjustments to demand		$51,228	($51,228)	-100.00%
Commodity Costs	$7,231,454	$9,045,690	($1,814,236)	-20.06%
TOTAL	$9,152,022	$10,634,316	($1,482,294)	-13.94%
SVI				
Commodity Costs	$1,715,977	$1,999,461	($283,484)	-14.18%
SMS included in commodity	$11,338	$12,991	($1,653)	-12.72%
FDD-1 Demand Charge	$16,517	$29,200	($12,683)	-43.43%
Adjustments		($13,062)	$13,062	-100.00%
TOTAL	$1,743,832	$2,028,590	($284,758)	-14.04%
LVI				
Commodity Costs	$2,388,649	$2,687,694	($299,045)	-11.13%
SMS	$15,587	$19,932	($4,345)	-21.80%
FDD-1 Demand Charge	$22,706	$44,258	($21,552)	-48.70%
TOTAL	$2,426,942	$2,751,884	($324,942)	-11.81%

Great Plains Natural Gas South District
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Recovery by Class		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
FIRM					
Demand		$1,920,568	$1,588,626	$331,942	20.89%
Commodity		$7,231,454	$9,045,690	($1,814,236)	-20.06%
	Total	$9,152,022	$10,634,316	($1,482,294)	-13.94%
INTERRUPTIBLE					
Commodity		$4,170,774	$4,780,474	($609,700)	-12.75%
	Total	$4,170,774	$4,780,474	($609,700)	-12.75%

Recovery by Component		(1) COST RECOVERY	(2) COST INCURRED	(3) (1)-(2) PRESENT YEAR OVER/(UNDER) RECOVERY ($)	(4) (3)/(2) PRESENT YEAR OVER/(UNDER) RECOVERY (%)
Demand					
Firm		$1,920,568	$1,588,626	$331,942	20.89%
	Total	$1,920,568	$1,588,626	$331,942	20.89%
Commodity					
Firm		$7,231,454	$9,045,690	($1,814,236)	-20.06%
Interruptible		$4,170,774	$4,780,474	($609,700)	-12.75%
	Total	$11,402,228	$13,826,164	($2,423,936)	**-17.53%**

Interstate Gas
2013-2014 True Up
Docket No. G001/AA-14-742
As filed on August 29, 2014

Ten Year Summary of Gas-Cost Recovery:

Year ended 6/30	PRESENT YEAR PERCENT OVER (UNDER) RECOVERY	CUMULATIVE PERCENT OVER (UNDER) RECOVERY
2004-2005	-2.36%	
2005-2006	-2.99%	
2006-2007	-1.20%	
2007-2008	1.67%	
2008-2009	5.42%	
2009-2010	-5.17%	
2010-2011	-0.65%	
2011-2012	-5.61%	
2012-2013	3.76%	
2013-2014	**5.92%**	**5.63%**
10-Year Average	-0.12%	

Recovery By Class	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)	(5) PRESENT YEAR OVER/(UNDER) BEGINNING BALANCE
RATE 511-FIRM	$8,978,504	$8,368,986	$609,518	**7.28%**	($22,309)
RATE 524-SMALL INTERRUPTIBLE	$1,740,911	$1,750,980	($10,069)	**-0.58%**	($7,121)
RATE 526-LARGE INTERRUPTIBLE	$0	$0	$0	**0%**	$0
TOTAL	**$10,719,415**	**$10,119,966**	**$599,448**	**5.92%**	**($29,430)**

(6) (3)+(5) TOTAL OVER/(UNDER) COLLECTION	(7) (6)/(2) **CUMM %**	(8) Estimated Sales (Mcf)	(9) (6)/(8) True-Up (Refund)/Collection
$587,209	**7.02%**	1,248,804	**(0.4702)**
($17,191)	**-0.98%**	426,751	**0.0403**
$0	**N/A**	0	**N/A**
$570,018	**5.63%**	**1,675,555**	

Interstate Gas
2013-2014 True Up
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RECOVERY BY CLASS	(1) COST RECOVERY	(2) COST INCURRED	(3) (1) - (2) PRESENT YEAR OVER/(UNDER) COLLECTION ($)	(4) (3) / (2) PRESENT YEAR OVER/(UNDER) COLLECTION (%)
RATE 511-FIRM				
ASSIGNED DEMAND COST	$1,864,012	$1,333,006	$531,005	39.84%
ALLOCATED DEMAND COST	$324,002	$263,866	$60,135	22.79%
COMMODITY COST	$6,790,491	$6,772,113	$18,377	0.27%
TOTAL	$8,978,504	$8,368,986	$609,518	7.28%
RATE 524-SMALL INTERRUPTIBLE				
ALLOCATED DEMAND COST	$82,144	$66,835	$15,309	22.91%
COMMODITY COST	$1,658,767	$1,684,145	($25,378)	-1.51%
TOTAL	$1,740,911	$1,750,980	($10,069)	-0.58%
RATE 526-LARGE INTERRUPTIBLE				
ALLOCATED DEMAND COST	$0.00	$0.00	$0.00	0.00%
COMMODITY COST	$0.00	$0.00	$0.00	0.00%
TOTAL	$0.00	$0.00	$0.00	0.00%
RECOVERY BY COMPONENT				
ASSIGNED DEMAND COST:				
RATE 511-FIRM	$1,864,012	$1,333,006	$531,005	39.84%
RATE 524-SMALL INTERRUPTIBLE	$0	$0	$0	0.00%
RATE 526-LARGE INTERRUPTIBLE	$0	$0	$0	0.00%
SUB TOTAL ASSIGNED	$1,864,012	$1,333,006	$531,005	39.84%
ALLOCATED DEMAND COST:				
RATE 511-FIRM	$324,002	$263,866	$60,135	22.79%
RATE 524-SMALL INTERRUPTIBLE	$82,144	$66,835	$15,309	22.91%
RATE 526-LARGE INTERRUPTIBLE	$0	$0	$0	0.00%
SUB TOTAL ALLOCATED	$406,146	$330,701	$75,444	22.81%
COMMODITY COSTS:				
RATE 511-FIRM	$6,790,491	$6,772,113	$18,377	0.27%
RATE 524-SMALL INTERRUPTIBLE	$1,658,767	$1,684,145	($25,378)	-1.51%
RATE 526-LARGE INTERRUPTIBLE	$0	$0	$0	0.00%
SUB TOTAL COMMODITY	$8,449,258	$8,456,259	($7,001)	-0.08%
TOTAL	$10,719,415	$10,119,966	$599,448	5.92%

Interstate Gas
2013-2014 True Up
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FIRM				
ASSIGNED DEMAND	Cost Incurred	Cost Recovery	Over (Under) Collectior	% Over (Under) Collection
TF-12 Base	$171,767	$185,291	$13,524	7.87%
TF-12 Variable	$815,759	$1,138,148	$322,390	39.52%
TF-5 & TFX	$364,127	$482,242	$118,116	32.44%
Interruptible Penalties	($37,118)		$37,118	-100.00%
SMS Demand	$44,010	$58,330	$14,320	32.54%
Capacity Release	($25,538)		$25,538	-100.00%
Subtotal Assigned Demand	$1,333,006	$1,864,012	$531,005	39.84%
ALLOCATED DEMAND				
CenterPoint Res.	$48,193	$59,068	$10,875	22.57%
Great Lakes Res.	$18,201	$21,746	$3,545	19.47%
Other Res.	$0	$0	$0	0%
FDD Reservation	$98,596	$120,345	$21,749	22.06%
FDD Capacity	$98,578	$120,345	$21,767	22.08%
Balancing	$298	$2,499	$2,200	737.80%
Subtotal Allocated Demand FIRM	$263,866	$324,002	$60,135	22.79%
Commodity FIRM	$6,772,113	$6,790,491	$18,377	0.27%
Total demand and commodity FIRM	$8,368,986	$8,978,504	$609,518	7.28%
SVI				
ALLOCATED DEMAND				
CenterPoint Res.	$12,207	$15,010	$2,803	22.96%
Great Lakes Res.	$4,610	$5,561	$951	20.62%
Other Res.	$0	$0	$0	0%
FDD Reservation	$24,974	$30,470	$5,497	22.01%
FDD Capacity	$24,969	$30,470	$5,501	22.03%
Balancing	$76	$633	$557	738.04%
Subtotal Allocated Demand SVI	$66,835	$82,144	$15,309	22.91%
Subtotal Allocated Demand FIRM	$263,866	$324,002	$60,135	22.79%
Total Allocated Demand SVI + FIRM	$330,701	$406,146	$75,444	22.81%
Commodity SVI	$1,684,145	$1,658,767	($25,378)	-1.51%
Commodity FIRM	$6,772,113	$6,790,491	$18,377	0.27%
Total Commodity SVI + FIRM	$8,456,259	$8,449,258	-$7,001	-0.08%
Total demand and commodity SVI	$1,750,980	$1,740,911	($10,069)	-0.58%

SUMMARY OF GAS COST RECOVERY SINCE 2005:

	Year Ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
MERC-PNG	2005	2.46%	
MERC-PNG	2006	-1.60%	
MERC-PNG	2007	-4.39%	
MERC-PNG	2008	1.21%	
MERC-PNG	2009	1.21%	
MERC-PNG	2010	-1.25%	
MERC-PNG	2011	2.58%	
MERC-PNG	2012	-6.19%	
MERC-PNG	2013	0.08%	
MERC-Northern System	2014	**-6.45%**	**-6.12%**
	10-YEAR AVERAGE	-1.23%	

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	$166,362,199	$177,169,742	($10,807,543)	**-6.10%**	$521,469
SVJ/LVJ/SLV Demand	$21,732	$21,731	$1	**0.00%**	$0
SVI/SVJ/LVI/LVJ/SLVI Commodity	$12,704,333	$14,243,520	($1,539,187)	**-10.81%**	$111,187
	$179,088,264	**$191,434,993**	**($12,346,729)**	**-6.45%**	**$632,656**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	CUMULATIVE %	ESTIMATED SALES (Mcf)	TRUE-UP FACTORS (REFUND)/COLLECT
GS	($10,286,074)	-5.81%	21,822,571	**$0.4714**
SVJ/LVJ/SLV Demand	$1	0.00%	1,140	**($0.0009)**
SVI/SVJ/LVI/LVJ/SLVI Commodity	($1,428,000)	-10.03%	2,707,300	**$0.5275**
	($11,714,073)	**-6.12%**	**24,531,011**	

MERC - NNG
2013-2014 True-up
Docket No. G011/AA-14-755
(As filed on September 2, 2014)

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY CLASS						
General Service (GS)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$45,350,159	$36,432,165	$8,917,994	24.48%
	COMMODITY		$121,012,040	$140,737,577	($19,725,537)	-14.02%
		TOTAL	$166,362,199	$177,169,742	($10,807,543)	-6.10%
Small & Large Volume Interruptible (SVI/LVI)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$0	$0	$0	0.00%
	COMMODITY		$12,624,943	$14,152,552	($1,527,609)	-10.79%
		TOTAL	$12,624,943	$14,152,552	($1,527,609)	-10.79%
Small & Large Volume Joint, Super Large Volume (SVJ/LVJ/SLV)			COST RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) COLLECTION ($)	PRESENT YEAR OVER/(UNDER) COLLECTION (%)
	DEMAND		$21,732	$21,731	$1	0.00%
	COMMODITY		$79,390	$90,968	($11,578)	-12.73%
		TOTAL	$101,122	$112,699	($11,577)	-10.27%

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY COMPONENT			RECOVERY	COST INCURRED	PRESENT YEAR OVER/(UNDER) RECOVERY	PRESENT YEAR OVER/(UNDER) RECOVERY
DEMAND	GS		$45,350,159	$36,432,165	$8,917,994	24.48%
DEMAND	SVI/LVI		$0	$0	$0	0.00%
DEMAND	SVJ/LVJ/SLV		$21,732	$21,731	$1	0.00%
		TOTAL	$45,371,891	$36,453,896	$8,917,995	24.46%
COMMODITY	GS		$121,012,040	$140,737,577	($19,725,537)	-14.02%
COMMODITY	SVI/LVI		$12,624,943	$14,152,552	($1,527,609)	-10.79%
COMMODITY	SVJ/LVJ/SLV		$79,390	$90,968	($11,578)	-12.73%
		TOTAL	$133,716,373	$154,981,097	($21,264,724)	-13.72%

MERC - Consolidated
2013-2014 True-up
Docket No. G011/AA-14-754
(As filed on September 2, 2014)

TEN YEAR SUMMARY OF GAS-COST RECOVERY SINCE 2004:

	Year ended 6/30	AS FILED PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
MERC-NMU	2004-2005	2.60%	
MERC-NMU	2005-2006	-1.56%	
MERC-NMU	2006-2007	-2.22%	
MERC-NMU	2007-2008	1.94%	
MERC-NMU	2008-2009	3.85%	
MERC-NMU	2009-2010	-2.09%	
MERC-NMU	2010-2011	2.00%	
MERC-NMU	2011-2012	-2.15%	
MERC-NMU	2012-2013	2.82%	
MERC-Consolidated	2013-2014	**-9.25%**	**-11.65%**
	10-YEAR AVERAGE	-0.41%	

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	$31,418,623	$34,713,498	($3,294,875)	**-9.49%**	($869,433)
SVJ Demand	$17,588	$17,588	$0	**0.00%**	$13
SVI/SJV/LVI Commodity	$5,079,998	$5,507,819	($427,821)	**-7.77%**	($97,257)
	$36,516,209	**$40,238,905**	**($3,722,696)**	**-9.25%**	**($966,677)**

	(6) (3) + (5)	(7) (6) / (2)	(8)	(9) (6) / (8)
	CURRENT YEAR TRUE-UP OVER/(UNDER) ENDING BALANCE	**CUMULATIVE %**	Estimated Sales (Mcf)	True-Up Factors (Refund)/Collection
GS	($4,164,308)	**-12.00%**	4,772,249	**$0.8726**
SVJ Demand	$13	**0.07%**	2,652	**($0.0049)**
SVI/SJV/LVI Commodity	($525,078)	**-9.53%**	920,648	**$0.5703**
	($4,689,373)	**-11.65%**	**5,695,549**	

MERC - Consolidated
2013-2014 True-up
Docket No. G011/AA-14-754
(As filed on September 2, 2014)

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		$4,860,538	$3,799,786	$1,060,752	27.92%
	COMMODITY		$26,558,085	$30,913,712	($4,355,627)	-14.09%
		TOTAL	$31,418,623	$34,713,498	($3,294,875)	-9.49%
SVI/SJV/LVI						
	DEMAND		$17,588	$17,588	$0	0.00%
	COMMODITY		$5,079,998	$5,507,819	($427,821)	-7.77%
		TOTAL	$5,097,586	$5,525,407	($427,821)	-7.74%

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)		$4,860,538	$3,799,786	$1,060,752	27.92%
DEMAND	SVI/SVJ/LVJ		$17,588	$17,588	$0	0.00%
		TOTAL	$4,878,126	$3,817,374	$1,060,752	27.79%
COMMODITY	General Service (GS)		$26,558,085	$30,913,712	($4,355,627)	-14.09%
COMMODITY	SVI/SVJ/LVJ		$5,079,998	$5,507,819	($427,821)	-7.77%
		TOTAL	$31,638,083	$36,421,531	($4,783,448)	-13.13%

CenterPoint Energy
2013 - 2014 True-Up
Docket No. G008/AA-14-752
As Filed on September 2, 2014

TEN YEAR SUMMARY OF GAS-COST RECOVERY:

Year Ended 6/30	PRESENT YEAR PERCENT OVER/ (UNDER) RECOVERY	CUMULATIVE PERCENT OVER/ (UNDER) RECOVERY
2004-2005	-0.61%	
2005-2006	-1.34%	
2006-2007	0.06%	
2007-2008	-0.44%	
2008-2009	1.17%	
2009-2010	-3.96%	
2010-2011	-0.66%	
2011-2012	-4.68%	
2012-2013	-0.84%	
2013-2014	**-6.88%**	**-5.62%**
10-YEAR AVERAGE	-1.82%	

RECOVERY BY CLASS

	(1)	(2)	(3)	(4) (3) / (2)	(5)	(6)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)	Credits Against Gas Costs	Inverted Block Rate Adjustment
SVF	$692,739,750	$744,874,402	($52,134,652)	**-7.00%**	$10,176,937	($25,595)
LGS	$0	$0	$0	**0.00%**	$0	$0
SVDF	$82,419,481	$87,201,243	($4,781,762)	**-5.48%**	$347,929	$0
LVDF	$65,528,544	$70,701,691	($5,173,147)	**-7.32%**	$297,046	$0
	$840,687,775	**$902,777,336**	**($62,089,561)**	**-6.88%**	**$10,821,912**	**($25,595)**

	(7)	(1) (3) + (5) + (6) + (7)	(2) (8) / (2)	(3)	(4) - (8) / (10)
	Prior Year True Up Over/(Under) Balance	Cumulative Over/(Under) Collection ($)	**CUMULATIVE %**	Estimated Sales (DT)	**True-Up Factors (Refund)/Collection**
SVF	$305,196	($41,678,114)	**-5.60%**	102,077,000	**$0.4083**
LGS	($1,660)	($1,660)	**0.00%**	101,800	**$0.0163**
SVDF	$189,106	($4,244,727)	**-4.87%**	13,454,000	**$0.3155**
LVDF	$25,936	($4,850,165)	**-6.86%**	11,741,000	**$0.4131**
	$518,578	**($50,774,666)**	**-5.62%**	**127,373,800**	

CenterPoint Energy
2013 - 2014 True-Up
Docket No. G008/AA-14-752
As Filed on September 2, 2014

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		$73,300,575	$72,787,228	$513,347	0.71%
	PROPANE		$0	$674,445	($674,445)	-100.00%
	COMMODITY		$619,439,175	$671,412,729	($51,973,554)	-7.74%
		TOTAL	$692,739,750	$744,874,402	($52,134,652)	-7.00%
LARGE GENERAL SERVICE						
	DEMAND		$0	$0	$0	0%
	COMMODITY		$0	$0	$0	0%
		TOTAL	$0	$0	$0	0.00%
SMALL VOLUME DUAL FUEL						
	COMMODITY		$82,419,481	$87,201,243	($4,781,762)	-5.48%
		TOTAL	$82,419,481	$87,201,243	($4,781,762)	-5.48%
LARGE VOLUME DUAL FUEL						
	COMMODITY		$65,528,544	$70,701,691	($5,173,147)	-7.32%
		TOTAL	$65,528,544	$70,701,691	($5,173,147)	-7.32%

			(1)	(2)	(3) (1) - (2)	(4) (3) / (2)
RECOVERY BY COMPONENT			RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) RECOVERY
DEMAND	SVF		$73,300,575	$72,787,228	$513,347	0.71%
PROPANE	SVF		$0	$674,445	($674,445)	-100.00%
		TOTAL	$73,300,575	$73,461,673	($161,098)	-0.22%
COMMODITY	SVF		$619,439,175	$671,412,729	($51,973,554)	-7.74%
COMMODITY	LGS		$0	$0	$0	0%
COMMODITY	SVDF		$82,419,481	$87,201,243	($4,781,762)	-5.48%
COMMODITY	LVDF		$65,528,544	$70,701,691	($5,173,147)	-7.32%
		TOTAL	$767,387,200	$829,315,663	($61,928,463)	-7.47%

TOTAL DEMAND AND COMMODITY

XCEL Gas
2013-2014 True Up
Docket No. G002/AA-14-736
As Filed August 29, 2014

Ten Year Summary of Gas-Cost Recovery:
Excludes Over/Under-Recoveries associated with fixed price programs terminated in 2006-2007 (Docket No. G002/CI-07-541).

Year ended 6/30	Present Year Percent Over/(Under) Recovery	Cumulative Percent Over/(Under) Recovery
2004-2005	-1.77%	
2005-2006	-1.35%	
2006-2007	0.32%	
2007-2008	-1.75%	
2008-2009	-0.23%	
2009-2010	-1.26%	
2010-2011	-0.50%	
2011-2012	-3.15%	
2012-2013	-0.36%	
2013-2014	**-10.47%**	**-10.43%**
10-YEAR AVG	-2.05%	

Recovery by Class

	(1)	(2)	(3) (1) - (2)	(4) (3) / (2)	(5)
	Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)	Present Year True-Up Over/(Under) Beginning Balance
Residential	$234,754,502	$258,646,928	($23,892,426)	**-9.24%**	$71,258
Commercial/Industrial Firm	$127,193,782	$142,006,537	($14,812,755)	**-10.43%**	$238,416
Demand Billed Demand	$1,500,595	$1,478,480	$22,115	**1.50%**	($4,162)
Demand Billed Commodity	$13,520,938	$15,653,885	($2,132,947)	**-13.63%**	$16,441
Small Interruptible	$13,327,096	$15,841,761	($2,514,665)	**-15.87%**	$6,593
Medium & Large Interruptible	$38,586,881	$45,404,654	($6,817,773)	**-15.02%**	($162,359)
TOTAL	**$428,883,794**	**$479,032,245**	**($50,148,451)**	**-10.47%**	**$166,187**

	(6)	(7)	(8) (7)/(2)	(9)	(10)
	Prior Period Adj. Over/(Under)	Total Over/(Under) Collection	Cumulative %	Estimated Sales Therms	**True-Up Factors (Refund)/Collection**
Residential	$0	($23,821,168)	**-9.21%**	348,776,906	**($0.06830)**
Commercial/Industrial Firm	$0	($14,574,339)	**-10.26%**	190,903,910	**($0.07634)**
Demand Billed Demand	$0	$17,953	**1.21%**	2,504,644	**$0.00717**
Demand Billed Commodity	$0	($2,116,506)	**-13.52%**	27,941,037	**($0.07575)**
Small Interruptible	$0	($2,508,072)	**-15.83%**	25,859,520	**($0.09699)**
Medium & Large Interruptible	$0	($6,980,132)	**-15.37%**	88,037,331	**($0.07929)**
TOTAL	**$0**	**($49,982,264)**	**-10.43%**		

XCEL Gas
2013-2014 True Up
Docket No. G002/AA-14-736
As Filed August 29, 2014

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	$35,748,577	$30,761,046	$4,987,531	16.21%
TU Sch. D, page 4	Commododity & Peak Shaving	$199,005,925	$227,885,882	($28,879,957)	-12.67%
	TOTAL	$234,754,502	$258,646,928	($23,892,426)	-9.24%
Commercial/Industrial Firm		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$19,098,544	$16,713,343	$2,385,201	14.27%
TU Sch. D, page 4	Commododity & Peak Shaving	$108,095,238	$125,293,194	($17,197,956)	-13.73%
	TOTAL	$127,193,782	$142,006,537	($14,812,755)	-10.43%
Demand Billed		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 3	Demand	$1,500,595	$1,478,480	$22,115	1.50%
TU Sch. D, page 4	Commododity & Peak Shaving	$13,520,938	$15,653,885	($2,132,947)	-13.63%
	TOTAL	$15,021,533	$17,132,365	($2,110,832)	-12.32%
Small Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$13,327,096	$15,841,761	($2,514,665)	-15.87%
	TOTAL	$13,327,096	$15,841,761	($2,514,665)	-15.87%
Medium & Large Interruptible		Cost Recovery	Cost Incurred	Present Year Over/(Under) Collection ($)	Present Year Over/(Under) Collection (%)
TU Sch. D, page 4	Commododity & Peak Shaving	$38,586,881	$45,404,654	($6,817,773)	-15.02%
	TOTAL	$38,586,881	$45,404,654	($6,817,773)	-15.02%

Recovery by Component		RECOVERY	COST INCURRED	OVER/(UNDER) RECOVERY	OVER/(UNDER) (%)
Demand	Residential	$35,748,577	$30,761,046	$4,987,531	16.21%
Demand	Commercial/Industrial Firm	$19,098,544	$16,713,343	$2,385,201	14.27%
Demand	Demand Billed	$1,500,595	$1,478,480	$22,115	1.50%
	TOTAL DEMAND	$56,347,716	$48,952,869	$7,394,847	15.11%
Commodity	Residential	$199,005,925	$227,885,882	($28,879,957)	-12.67%
Commodity	Commercial/Industrial Firm	$108,095,238	$125,293,194	($17,197,956)	-13.73%
Commodity	Demand Billed	$13,520,938	$15,653,885	($2,132,947)	-13.63%
Commodity	Small Interruptible	$13,327,096	$15,841,761	($2,514,665)	-15.87%
Commodity	Medium & Large Interruptible	$38,586,881	$45,404,654	($6,817,773)	-15.02%
	TOTAL COMMODITY	$372,536,078	$430,079,376	($57,543,298)	-13.38%

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	$ 5.4390	**8**	$ 0.4704	9.47%	$ 0.5468	11.18%	$ 5.5679	**6**	$ 0.0432	0.78%	$ 0.0847	1.55%	-2.32%	**2**
Great Plains North***	$ 5.3271	**7**	$ 0.3585	7.22%	$ 0.4349	8.89%	$ 6.3654	**8**	$ 0.8407	15.22%	$ 0.8823	16.09%	-16.31%	**7**
Great Plains South	$ 4.4510	**1**	$ (0.5176)	-10.42%	$ (0.4412)	-9.02%	$ 5.3973	**2**	$ (0.1274)	-2.31%	$ (0.0859)	-1.57%	-17.53%	**8**
Interstate Gas	$ 4.5894	**2**	$ (0.3792)	-7.63%	$ (0.3028)	-6.19%	$ 4.5932	**1**	$ (0.9314)	-16.86%	$ (0.8899)	-16.23%	-0.08%	**1**
MERC-Consolidated	$ 4.7650	**5**	$ (0.2036)	-4.10%	$ (0.1272)	-2.60%	$ 5.4855	**5**	$ (0.0392)	-0.71%	$ 0.0023	0.04%	-13.13%	**4**
MERC-NNG	$ 4.6696	**3**	$ (0.2990)	-6.02%	$ (0.2226)	-4.55%	$ 5.4122	**3**	$ (0.1125)	-2.04%	$ (0.0710)	-1.29%	-13.72%	**6**
CenterPoint Energy****	$ 5.1693	**6**	$ 0.2007	4.04%	$ 0.2771	5.66%	$ 5.5865	**7**	$ 0.0618	1.12%	$ 0.1034	1.89%	-7.47%	**3**
Xcel Gas	$ 4.7271	**4**	$ (0.2415)	-4.86%	$ (0.1651)	-3.38%	$ 5.4572	**4**	$ (0.0674)	-1.22%	$ (0.0259)	-0.47%	-13.38%	**5**
Weighted MN Average	**$ 4.9686**						**$ 5.5247**						**-10.07%**	
Non-Weighted MN Average	**$ 4.8922**						**$ 5.4831**						**-10.78%**	
Standard Deviation	**$ 0.3673**						**$ 0.4783**							

***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****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 Costs²

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	$ 6,343,225	1,030,069	$ 6.1581	**6**	$ 0.4974	8.79%	$ 0.3597	6.20%	$ 6,360,602	1,030,069	$ 6.1749	**6**	$ 0.0270	0.44%	$ (0.0519)	-0.83%	$ (0.0169)	-0.27%
Great Plains North***	$ 12,200,500	1,922,282	$ 6.3469	**8**	$ 0.6862	12.12%	$ 0.5485	9.46%	$ 13,878,652	1,922,282	$ 7.2199	**8**	$ 1.0720	17.44%	$ 0.9931	15.95%	$ (0.8730)	-12.09%
Great Plains South	$ 13,322,796	2,561,700	$ 5.2008	**1**	$ (0.4599)	-8.13%	$ (0.5976)	-10.31%	$ 15,414,790	2,561,700	$ 6.0174	**2**	$ (0.1305)	-2.12%	$ (0.2094)	-3.36%	$ (0.8166)	-13.57%
Interstate Gas	$ 10,719,415	1,841,021	$ 5.8225	**5**	$ 0.1618	2.86%	$ 0.0241	0.42%	$ 10,119,966	1,841,021	$ 5.4969	**1**	$ (0.6510)	-10.59%	$ (0.7299)	-11.72%	$ 0.3256	5.92%
MERC-Consolidated	$ 36,516,208	6,639,650	$ 5.4997	**3**	$ (0.1610)	-2.84%	$ (0.2987)	-5.15%	$ 40,238,904	6,639,650	$ 6.0604	**3**	$ (0.0875)	-1.42%	$ (0.1664)	-2.67%	$ (0.5607)	-9.25%
MERC-NNG	$ 179,088,264	28,635,598	$ 6.2540	**7**	$ 0.5933	10.48%	$ 0.4556	7.86%	$ 191,434,993	28,635,598	$ 6.6852	**7**	$ 0.5373	8.74%	$ 0.4584	7.36%	$ (0.4312)	-6.45%
CenterPoint Energy****	$ 840,687,775	148,449,728	$ 5.6631	**4**	$ 0.0024	0.04%	$ (0.1353)	-2.33%	$ 902,777,336	148,449,728	$ 6.0814	**5**	$ (0.0666)	-1.08%	$ (0.1454)	-2.34%	$ (0.4183)	-6.88%
Xcel Gas	$ 428,883,794	78,808,906	$ 5.4421	**2**	$ (0.2186)	-3.86%	$ (0.3563)	-6.15%	$ 479,032,245	78,808,906	$ 6.0784	**4**	$ (0.0695)	-1.13%	$ (0.1484)	-2.38%	$ (0.6363)	-10.47%
Mn Weighted Average	**$ 1,527,761,977**	**269,888,953**	**$ 5.6607**						**$ 1,659,257,488**	**269,888,953**	**$ 6.1479**						**$ (0.4872)**	**-7.92%**
Mn Non-Weighted Average			**$ 5.7984**								**$ 6.2268**						**$ (0.4284)**	**-6.88%**
Standard Deviation			**$ 0.4192**								**$ 0.5136**							
											$6.7404							

***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****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 tie to Attachment G15 and G16.

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2013 - June 30, 2014

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		2012-2013	2013-2014			2012-2013	2013-2014			2012-2013	2013-2014			2012-2013	2013-2014		
Company	Tariff Rate Designation	Annual Customer Charge ($)	Annual Customer Charge ($)	$ Diff (2) - (1)	% Diff (3)/(1)	Average Combined Commodity and Demand Charges ($/Mcf)	Average Combined Commodity and Demand Charges ($/Mcf)	$ Diff (6) - (5)	% Diff (7)/(5)	Average Non-Gas Commodity Margin ($/Mcf)	Average Non-Gas Commodity Margin ($/Mcf)	$ Diff (10) - (9)	% Diff (11)/(9)	Average True-Up ($/Mcf)	Average True-Up ($/Mcf)	$ Diff (14) - (13)	% Diff (15)/(13)
Greater Minnesota Gas	RS-1	$102.00	$102.00	$0.00	0.00%	$4.6262	$6.0543	$1.4281	30.87%	$4.4433	$4.4433	$0.0000	0.00%	$0.0668	$0.0445	($0.0224)	-33.49%
Great Plains North	N60	$78.00	$78.00	$0.00	0.00%	$5.6699	$6.3993	$0.7294	12.86%	$1.7602	$1.7864	$0.0262	1.49%	$0.5810	$0.4645	($0.1165)	-20.06%
Great Plains South	S60	$78.00	$78.00	$0.00	0.00%	$4.6536	$5.4795	$0.8259	17.75%	$1.3762	$1.4024	$0.0262	1.90%	$0.1977	$0.0756	($0.1221)	-61.77%
Interstate Gas	010	$60.00	$60.00	$0.00	0.00%	$4.8527	$5.8062	$0.9535	19.65%	$1.9769	$1.9769	$0.0000	0.00%	$0.2228	($0.1491)	($0.3718)	-166.91%
MERC-CON	3H801/3HS01	$99.36	$108.55	$9.19	9.25%	$4.8096	$5.4168	$0.6072	12.63%	$2.1972	$2.1022	($0.0949)	-4.32%	$0.0657	($0.2572)	($0.3228)	-491.72%
MERC-NNG	301 / 2HS012HS	$98.58	$108.55	$9.97	10.11%	$5.2945	$6.2139	$0.9194	17.37%	$1.9586	$2.1022	$0.1437	7.34%	$0.1900	($0.0033)	($0.1934)	-101.75%
CenterPoint Energy	Residential	$96.00	$99.51	$3.51	3.66%	$4.3258	$5.4134	$1.0875	25.14%	$1.7841	$2.0034	$0.2194	12.30%	$0.1774	$0.0330	($0.1443)	-81.38%
Xcel Gas	101	$108.00	$108.00	$0.00	0.00%	$4.4095	$5.4210	$1.0115	22.94%	$1.8591	$1.8591	$0.0000	0.00%	$0.1121	($0.0048)	($0.1169)	-104.28%
MN NON-WEIGHTED AVERAGE		$91.71	$92.83	$1.12	1.22%	$4.70	$5.78	$1.0741	22.85%	$2.13	$2.21	$0.0822	3.87%	$0.1569	$0.0254	($0.1315)	-83.81%

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2013 - June 30, 2014

		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)
		2012-2013	2013-2014			2012-2013	2013-2014			2012-2013	2013-2014			2012-2013	2013-2014		
Company	Tariff Rate Designation	Average Total Cost of Gas ($/Mcf) (6)+(10)+(14)	Average Total Cost of Gas ($/Mcf) (6)+(10)+(14)	$ Diff (18) - (17)	% Diff (19)/(17)	Average Use (Mcf)	Average Use (Mcf)	Mcf Diff (22) - (21)	% Diff (23)/(21)	Total Average Customer Use (Mcf)	Total Average Customer Use (Mcf)	Mcf Diff (26) - (25)	% Diff (27)/(25)	Average Number of Customers	Average Number of Customers	Customer Diff (30) - (29)	% Diff (31)/(29)
Greater Minnesota Gas	RS-1	$9.1364	$10.5420	$1.4057	15.39%	7.43	8.32	0.88	11.88%	89.20	99.80	10.60	11.88%	4,314	4,643	329.33	7.63%
Great Plains North	RS-1	$8.0111	$8.6502	$0.6391	7.98%	6.98	7.58	0.60	8.60%	83.70	90.90	7.20	8.60%	8,077	8,120	43.17	0.53%
Great Plains South	RS-1	$6.2276	$6.9575	$0.7300	11.72%	6.55	7.13	0.58	8.78%	78.60	85.50	6.90	8.78%	9,904	9,937	33.83	0.34%
Interstate Gas	511	$7.0524	$7.6341	$0.5817	8.25%	7.56	8.53	0.98	12.94%	90.67	102.40	11.73	12.94%	9,303	9,308	4.83	0.05%
MERC-CON	GS	$7.0724	$7.2618	$0.1895	2.68%	7.75	8.40	0.66	8.48%	92.95	100.84	7.88	8.48%	35,678	28,479	(7,199.25)	-20.18%
MERC-NNG	GSTP	$7.4431	$8.3128	$0.8697	11.69%	7.41	8.48	1.07	14.45%	88.87	101.71	12.84	14.45%	144,716	162,682	17,966.17	12.41%
CenterPoint Energy	Residential	$6.2873	$7.4498	$1.1626	18.49%	7.84	8.80	0.96	12.22%	94.10	105.60	11.50	12.22%	745,201	752,407	7,206.00	0.97%
Xcel Gas	Res	$6.3807	$7.2753	$0.8946	14.02%	7.56	8.49	0.92	12.20%	90.78	101.85	11.07	12.20%	404,673	407,523	2,849.25	0.70%
MN NON-WEIGHTED AVERAGE		$6.9856	$8.0105	$1.0248	14.67%	7.37	8.21	0.85	11.51%	88.40	98.57	10.18	11.51%	137,085	172,888	35,802.34	26.12%

AVERAGE RESIDENTIAL BILLS ANALYSIS
ATTACHMENT G13 (SUPPORTING GRAPH 1, TABLE G4 AND TABLE G7)
July 1, 2013 - June 30, 2014

Company	Tariff Rate Designation	(33) 2012-2013 Average Total Monthly Bill ($) [(2)/12]+[(18)*(22)]	(34) 2013-2014 Average Total Monthly Bill ($) [(2)/12]+[(18)*(22)]	(35) $ Diff (34) - (33)	(36) % Diff (35)/(33)	(37) 2012-2013 Average Total Annual Bill ($) (2)+[(18)*(26)]	(38) 2013-2014 Average Total Annual Bill ($) (2)+[(18)*(26)]	(39) $ Diff (38) - (37)	(40) % Diff (39)/(37)	(41) 2012-2013 Average Total Annual Bill at 140 Mcf/Year ($) (1)+[(18)*140]	(42) 2013-2014 Average Total Annual Bill at 140 Mcf/Year ($) (1)+[(18)*140]	(43) $ Diff (42) - (41)	(44) % Diff (43)/(41)
Greater Minnesota Gas	RS-1	$76.41	$96.17	$19.76	$0.26	$916.96	$1,154.10	$237.13	$0.26	$1,381.09	$1,577.89	$196.79	$0.14
Great Plains North	RS-1	$62.38	$72.03	$9.65	$0.15	$748.53	$864.30	$115.77	$0.15	$1,199.56	$1,289.03	$89.47	$0.07
Great Plains South	RS-1	$47.29	$56.07	$8.78	$0.19	$567.49	$672.87	$105.38	$0.19	$949.86	$1,052.05	$102.19	$0.11
Interstate Gas	511	$58.29	$70.15	$11.86	$0.20	$699.44	$841.75	$142.31	$0.20	$1,047.33	$1,128.77	$81.44	$0.08
MERC-CON	GS	$63.06	$70.07	$7.00	$0.11	$756.75	$840.80	$84.05	$0.11	$1,089.49	$1,125.21	$35.72	$0.03
MERC-NNG	GSTP	$63.34	$79.50	$16.17	$0.26	$760.03	$954.04	$194.02	$0.26	$1,140.61	$1,272.34	$131.73	$0.12
CenterPoint Energy	Residential	$57.30	$73.85	$16.55	$0.29	$687.63	$886.22	$198.59	$0.29	$976.22	$1,142.48	$166.27	$0.17
Xcel Gas	Res	$57.27	$70.75	$13.48	$0.24	$687.22	$848.98	$161.75	$0.24	$1,001.30	$1,126.54	$125.24	$0.13
MN NON-WEIGHTED AVERAGE		$59.11	$73.57	$14.46	24.47%	$709.34	$882.88	$173.55	24.47%	$1,069.70	$1,214.29	$144.59	13.52%

Attachment G14
Daily Delivery Variance Charges (DDVC)
Supporting Tables G12 and G13

Source IR 7

DDVC Volumes (MMbtu)			
Company	Positive & Negative	punitive	total
Greater Minnesota	4,216	-	4,216
Great Plains	40,421	-	40,421
Interstate	-	-	-
CPE	162,693	-	162,693
MERC-CON	-	-	-
Xcel Gas-MN	217,941	-	217,941
MERC-NNG	26,330	-	26,330
MN Totals	451,601	-	451,601

In its response, GMG's total vols. of 7,580 mcf do not agree with the detail.

	DDVC ($)				Percent of Total Costs Incurred		
Company	Positive & Negative	punitive	total	Actual Incurred Gas Cost ($)	Positive & Negative	punitive	total
Greater Minnesota	$3,075	$3,642	$6,717	$6,360,602	0.0483%	0.0573%	0.1056%
Great Plains	$31,412	$0	$31,412	$29,293,442	0.1072%	0.0000%	0.1072%
Interstate	$0	$0	$0	$10,119,966	0.0000%	0.0000%	0.0000%
CPE	$69,897	$0	$69,897	$902,777,336	0.0077%	0.0000%	0.0077%
MERC-CON	$0	$0	$0	$40,238,905	0.0000%	0.0000%	0.0000%
Xcel Gas-MN	$50,959	$0	$50,959	$479,032,245	0.0106%	0.0000%	0.0106%
MERC-NNG	$10,297	$0	$10,297	$191,434,993	0.0054%	0.0000%	0.0054%
MN Totals	$165,640	$3,642	$169,282	$1,659,257,489	0.0100%	0.0002%	0.0102%

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

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	1,030,069	$ 5,602,507	$ 5.4390	1,030,069	$ 5,735,287	$ 5.5679	-2.32%
Great Plains North	1,922,282	$ 10,240,263	$ 5.3271	1,922,282	$ 12,236,102	$ 6.3654	-16.31%
Great Plains South	2,561,700	$ 11,402,228	$ 4.4510	2,561,700	$ 13,826,164	$ 5.3973	-17.53%
Interstate Gas	1,841,021	$ 8,449,258	$ 4.5894	1,841,021	$ 8,456,259	$ 4.5932	-0.08%
MERC-Consolidated***	6,639,650	$ 31,638,083	$ 4.7650	6,639,650	$ 36,421,531	$ 5.4855	-13.13%
MERC-NNG***	28,635,598	$ 133,716,373	$ 4.6696	28,635,598	$ 154,981,097	$ 5.4122	-13.72%
CenterPoint Energy****	148,449,728	$ 767,387,200	$ 5.1693	148,449,728	$ 829,315,663	$ 5.5865	-7.47%
Xcel Gas	78,808,906	$ 372,536,078	$ 4.7271	78,808,906	$ 430,079,376	$ 5.4572	-13.38%
MN Weighted Average	269,888,953	$ 1,340,971,990	$ 4.9686	269,888,953	$ 1,491,051,479	$ 5.5247	-10.07%
MN Non-Weighted Average			$ 4.8922			$ 5.4831	-10.78%

***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: CenterPoint Energy's Northern area merged with the Viking area in July 2005 and became Northern and Viking area combined.
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	$ 6,343,225	1,030,069	$ 6.1581	**6**	$ 6,360,602	1,030,069	$ 6.1749	**6**	$ (0.0169)	-0.27%
Great Plains North***	$ 12,200,500	1,922,282	$ 6.3469	**8**	$ 13,878,652	1,922,282	$ 7.2199	**8**	$ (0.8730)	-12.09%
Great Plains South	$ 13,322,796	2,561,700	$ 5.2008	**1**	$ 15,414,790	2,561,700	$ 6.0174	**2**	$ (0.8166)	-13.57%
Interstate Gas	$ 10,719,415	1,841,021	$ 5.8225	**5**	$ 10,119,966	1,841,021	$ 5.4969	**1**	$ 0.3256	5.92%
MERC-Consolidated	$ 36,516,208	6,639,650	$ 5.4997	**3**	$ 40,238,904	6,639,650	$ 6.0604	**3**	$ (0.5607)	-9.25%
MERC-NNG	$ 179,088,264	28,635,598	$ 6.2540	**7**	$ 191,434,993	28,635,598	$ 6.6852	**7**	$ (0.4312)	-6.45%
CenterPoint Energy	$ 840,687,775	148,449,728	$ 5.6631	**4**	$ 902,777,336	148,449,728	$ 6.0814	**5**	$ (0.4183)	-6.88%
Xcel Gas	$ 428,883,794	78,808,906	$ 5.4421	**2**	$ 479,032,245	78,808,906	$ 6.0784	**4**	$ (0.6363)	-10.47%
Mn Weighted Average	**$ 1,527,761,977**	**269,888,953**	**$ 5.6607**		**$ 1,659,257,488**	**269,888,953**	**$ 6.1479**		**$ (0.4872)**	**-7.92%**
Mn Non-Weighted Average			**$ 5.7984**				**$ 6.2268**		**$ (0.4284)**	**-6.88%**
Standard Deviation			**0.4192**				**0.5136**			

***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****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 Costs1
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	$ 5,800,693	899,711	$ 6.4473	**7**	$ 5,831,967	899,711	$ 6.4820	**5**	$ (0.0348)	-0.54%
Great Plains North	$ 9,021,783	1,287,806	$ 7.0055	**8**	$ 10,357,111	1,287,806	$ 8.0424	**8**	$ (1.0369)	-12.89%
Great Plains South	$ 9,152,022	1,595,713	$ 5.7354	**3**	$ 10,634,316	1,595,713	$ 6.6643	**6**	$ (0.9289)	-13.94%
Interstate Gas ******	$ 8,978,504	1,468,732	$ 6.1131	**5**	$ 8,368,986	1,468,732	$ 5.6981	**1**	$ 0.4150	7.28%
MERC-Consolidated*** 2	$ 31,418,623	5,555,908	$ 5.6550	**2**	$ 34,713,498	5,555,908	$ 6.2480	**4**	$ (0.5930)	-9.49%
MERC-NNG*** 2	$ 166,362,199	25,837,253	$ 6.4389	**6**	$ 177,169,742	25,837,253	$ 6.8571	**7**	$ (0.4183)	-6.10%
CenterPoint Energy*****	$ 692,739,750	119,582,222	$ 5.7930	**4**	$ 744,874,402	119,582,222	$ 6.2290	**3**	$ (0.4360)	-7.00%
Xcel Gas****	$ 376,969,817	67,414,278	$ 5.5918	**1**	$ 417,785,830	67,414,278	$ 6.1973	**2**	$ (0.6055)	-9.77%
Mn Weighted Average	**$ 1,300,443,391**	**223,641,624**	**$ 5.8149**		**$ 1,409,735,852**	**223,641,624**	**$ 6.3035**		**$ (0.4887)**	**-7.75%**
Mn Non-Weighted Average			**$ 6.0975**				**$ 6.5523**		**$ (0.4548)**	**-6.94%**

***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: 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: Subtracted Interstate's company use & interdepartmental from firm volumes.
1 The numbers reported in this table are from the true up filings and utility AAA reports.
2 MERC's Interruptible numbers include the Joint customers since Joint customers are not considered firm on the peak day.

This Table was prepared as requested by Commission Staff (See Commission staff briefing papers of November 8, 2001 in Docket No. E,G999/AA-00-1027, page 31). Please keep in mind that the comparisions between the regulated utilities will not be an "apples-to-apples" comparision as each utility has different rate structures and tariffs.

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	$	542,532	130,358	$	4.1619	**1**	$	528,635	130,358	$	4.0553	**1**	$	0.1066	2.63%
Great Plains North***	$	3,178,717	634,476	$	5.0100	**7**	$	3,521,541	634,476	$	5.5503	**8**	$	(0.5403)	-9.74%
Great Plains South	$	4,170,774	965,987	$	4.3176	**2**	$	4,780,474	965,987	$	4.9488	**3**	$	(0.6312)	-12.75%
Interstate Gas	$	1,740,911	372,289	$	4.6762	**5**	$	1,750,980	372,289	$	4.7033	**2**	$	(0.0270)	-0.58%
MERC-Consolidated *	$	5,097,585	1,083,742	$	4.7037	**6**	$	5,525,406	1,083,742	$	5.0985	**5**	$	(0.3948)	-7.74%
MERC-NNG *	$	12,726,065	2,798,345	$	4.5477	**3**	$	14,265,251	2,798,345	$	5.0977	**4**	$	(0.5500)	-10.79%
CenterPoint Energy*****	$	147,948,025	28,867,506	$	5.1251	**8**	$	157,902,934	28,867,506	$	5.4699	**7**	$	(0.3448)	-6.30%
Xcel Gas****	$	51,913,977	11,394,627	$	4.5560	**4**	$	61,246,415	11,394,627	$	5.3750	**6**	$	(0.8190)	-15.24%
Mn Weighted Average	**$**	**227,318,586**	**46,247,330**	**$**	**4.9153**		**$**	**249,521,636**	**46,247,330**	**$**	**5.3954**		**$**	**(0.4801)**	**-8.90%**
Mn Non-Weighted Average				**$**	**4.6373**					**$**	**5.0374**		**$**	**(0.4001)**	**-7.94%**

*NOTE: MERC's Interruptible numbers include the joint customers since Joint customers are not considered firm on the peak day.
***NOTE: Great Plains' Crookston district merged with the North-4 district in February 2004 and became the North district.
****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 G19

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	1,043,617	0	1,043,617	1,030,069	15,798	0	1,045,867	(2,250)	-0.22%
Great Plains total co. #	4,643,912	(82,256)	4,561,656	4,464,228	0	4,719	4,468,947	92,709	2.03%
Great Plains North								26,286	0.58%
Great Plains South								66,423	1.46%
Interstate	1,863,604	0	1,863,604	1,842,091	1,070	0	1,843,161	20,443	1.10%
MERC-Consolidated **	6,738,715	0	6,738,715	6,713,260	0	0	6,713,260	25,455	0.38%
MERC-NNG **	27,753,523	0	27,753,523	28,535,072	0	0	28,535,072	(781,549)	-2.82%
CenterPoint Energy	150,815,133	(233,830)	150,581,303	148,449,725	154,128	0	148,603,853	1,977,450	1.31%
Xcel Gas Mn jurisdiction *	78,471,049	1,118,546	79,589,595	78,545,647	10,988	0	78,556,635	1,032,960	1.30%
Statewide Totals	271,329,553	802,460	272,132,013	269,580,092	181,984	4,719	269,766,795	2,457,927	0.90%

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's company use gas volumes (19,238 Dth for MERC-CON & 11,603 Dth for MERC-NNG) are subtracted from the Purchased Gas, column (1).
MERC-CON's Purchased Gas adjusted for GLGT's metering error for the period February through July 2014 per response to revised IR 10.
MERC-NNG's Consumer Use Gas adjusted for Deer River customers' billing errors for the period July 2013 to October 2014 per response to revised IR 10.

Attachment G20
Supporting Schedule to Tables G9 and G10

	Firm Design Day Demand (Mcf) (1)	Firm Design Day Deliverability **w/ Peak-Shaving** (Mcf) (2)	Actual Peak Day Date (Mcf) (3)	Design-Day Customer Numbers (4)	Actual Firm Peak Day Usage (Mcf) (5)	Annual Firm Throughput (Mcf) (6)	Design-Day Use Per Customer (7)	Peak-Day Use Per Design-Day Customer (8)	Annual Firm Load Factor (9)	Reserve Margin (10)	Annual Firm Requirement % (11)
Source:	**IR#2**	**IR#2**	**IR#3**	**IR#2**	**IR#3**	**IR#2**	**(7)=(1)/(4)**	**(8)=(1)/(5)**	**(9)=((6)/365)/(5)**	**(10)=((2)-(1))/(1)**	**(11)=(5)/(2)**
Greater Minnesota	8,917	9,559	01/06/14	5,204	7,880	899,711	1.7135	1.1316	31.28%	7.20%	82.4%
Great Plains North District #	14,140	15,000	01/05/14	11,579	13,109	1,600,823	1.2212	1.0786	33.46%	6.08%	87.4%
Great Plains South District	15,293	15,645	01/05/14	11,649	14,266	1,595,713	1.3128	1.0720	30.65%	2.30%	91.2%
Interstate Gas	13,035	14,219	01/06/14	10,676	11,230	1,469,802	1.2210	1.1607	35.86%	9.08%	79.0%
CenterPoint Energy	1,288,000	1,340,099	01/06/14	823,790	1,086,330	119,582,224	1.5635	1.1856	30.16%	4.04%	81.1%
MERC-CON	50,048	52,959	01/05/14	34,007	39,220	4,509,638	1.4717	1.2761	31.50%	5.82%	74.1%
Xcel Gas (Mn JURISDICTION)	706,935	749,325	01/06/14	441,573	538,794	73,019,076	1.6009	1.3121	37.13%	6.00%	71.9%
MERC-NNG	245,878	256,385	01/06/14	178,578	213,608	21,397,632	1.3769	1.1511	27.44%	4.27%	83.3%
Totals	**2,342,246**	**2,453,191**		**1,517,056**	**1,924,437**	**224,074,619**	**1.5439**	**1.2171**	**31.90%**	**4.74%**	78.4%
TOTAL prior year		2,430,901									
change from prior year		22,290									

The North District 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
Report

Docket No. **G999/AA-14-580; G022/AA-14-728; G002/AA-14-736; G001/AA-14-742; G004/AA-14-749; G008/AA-14-752; G011/AA-14-754 and G011/AA-14-755**

Dated this 5th day of May 2015

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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