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March 25, 2015

VIA ELECTRONIC FILING

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

RE: Petition for Change in Contract Demand Entitlement
Docket No. ___________________________

Dear Mr. Wolf:

Attached hereto, please find Greater Minnesota Gas, Inc.'s Petition for Change in Contract Demand Entitlement for 2015-2016 Heating Season for filing in a new docket.

All individuals identified on the attached service list have been electronically served with the same.

Thank you for your assistance. Please do not hesitate to contact me should you have any questions or concerns or if you require additional information. My direct dial number is (507) 665-8657 and my email address is kanderson@greatermngas.com.

Sincerely,

GREATER MINNESOTA GAS, INC.

/s/
Kristine A. Anderson
Corporate Attorney

Enclosure

cc: Service List

CERTIFICATE OF SERVICE

I, Kristine Anderson, hereby certify that I have this day served a true and correct copy of the following document to all persons at the addresses indicated on the attached list by electronic filing, electronic mail, or by depositing the same enveloped with postage paid in the United States Mail at Le Sueur, Minnesota:

Greater Minnesota Gas, Inc.'s Petition for Change in Contract Demand Entitlement for 2015-2016 Heating Season
Docket No. __________________

filed this 25th day of March, 2015.

/s/ Kristine A. Anderson
Kristine A. Anderson, Esq.
Corporate Attorney
Greater Minnesota Gas, Inc.

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STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

MPUC Docket No. ______________

PETITION FOR CHANGE IN CONTRACT DEMAND ENTITLEMENT FOR 2015-2016 HEATING SEASON

OVERVIEW

Greater Minnesota Gas, Inc. ("GMG") submits this filing to the Minnesota Public Utilities Commission ("Commission") to notify the Commission of a change in contract demand entitlement effective November 1, 2015. GMG will include the rate impact of these changes in GMG's Purchased Gas Adjustments effective November 1, 2015, pending Commission approval.

GMG's analysis demonstrates that with the proposed changes, GMG will have sufficient capacity to serve its firm customers during the 2015-2016 heating season without subjecting its ratepayers to paying unduly high amounts for maintaining its reserve. GMG's anticipated growth for purposes of this Petition is consistent with its anticipated growth reflected in its capital structure filing for 2015. In light of the early filing of this Petition and its expectation of new customer growth, GMG anticipates informally reviewing its projections, demand entitlement, and reserve margin immediately prior to the heating season to ensure that adequate capacity will be available to meet projected peak day demand and design day conditions. In the event that an adjustment of its contract demand request is necessary at that time, GMG will undertake appropriate action to address that scenario.

Minnesota Rule 7825.2910 Subp. 2 requires GMG to identify four things when filing for a change in demand, namely: discussion of the factors contributing to the need for changing demand; GMG's design day demand analysis; a summary of GMG's customers' winter and summer usage for all customer classes; and, a description of GMG's design day gas supply from all sources under it proposed level. This Petition addresses each of the requisite four areas based on GMG's analysis of its current customer usage and patterns, the impact GMG's current and anticipated growth on the upcoming heating season, and forecasting the size and expected load of new and recently acquired customers. GMG notes that, given the early filing of this Petition, GMG's calculations are limited to data acquired through February 28, 2015 with respect to data for the 2014-2015 heating season.

DISCUSSION

GMG's demand entitlement filings in recent years have reflected substantial changes as a direct result of the Company's growth. In order to address both a narrow reserve margin and the uncertainty of predictive modeling for conversion customers, GMG's reserve margin was increased for the 2013-2014 heating season and was maintained at a similar level for the majority of the 2014-2015 heating season.[1] GMG's increased customer base resulted in preventing any adverse rate impact on GMG's ratepayers despite GMG purchasing increased reserve capability. GMG's reserve margin has consistently been sufficient to ensure that its customers' needs were satisfied through the duration of the heating season, including on unseasonably cold days. GMG has continued to experience growth and anticipates a continued aggressive growth pattern. GMG's supply portfolio changes assured reliable firm supply for its customer base. Accordingly, GMG continued to employ similar modeling theories in developing its contract demand entitlement proposal for the 2015-2016 heating season as those used in recent years. GMG again utilized a combination of analytical tools to balance the competing components of maintaining a sufficient reserve and maintaining reasonable customer rates. By combining statistical regression analysis based on its existing customer data, projected growth information, and budget year analysis, GMG's proposed demand entitlement is again soundly supported by its supporting data, attached hereto and incorporated by reference.

GMG seeks an increase in total demand entitlement as follows:

Previous Proposed Entitlement Nov-Jan (Dth)	Previous Proposed Entitlement Feb-March (Dth)	Proposed Entitlement 2015-16 (Dth)	Entitlement Changes (Dth)	% Change From Previous Year
9,659	10,859	12,509	1650	15.19%

1. GMG Requires an Increase in Demand to Account for Growth and the Corresponding Change in its Design Day Calculations to Assure Its Ability to Maintain an Adequate Reserve Margin.

An increase in demand entitlement is requested by GMG to insure that it has sufficient reserve to meet its customers' needs. GMG's prior reserve margin level satisfactorily balanced the necessity of a sufficient reserve margin against protection for its ratepayers from an unreasonable reserve cost. The Department has previously noted that the OES generally uses a

[1] . GMG notes that it filed an Amendment to its Petition for Change in Contract Demand Entitlement in Docket No. G022/M-14-651 on February 12, 2015 due to an additional transportation contract acquired during Viking's open season. The additional transportation contract is a long-term contract and its long-term impact is illustrated in this Petition. The additional transportation contract did result in a substantial increase in GMG's reserve margin during February, 2015 and March, 2015 as reflected in the Amendment.

gauge of five percent to determine the appropriateness of firm's reserve margin. However, for the 2013-2014 heating season, the Department and Commission approved a reserve margin of 7.2%. While the Commission has not yet considered GMG's demand entitlement request for the 2014-2015 heating season, the Department recommended approval of its proposed reserve margin of 7.7%. (Docket No. G022/M-14-651, Comments of the Minnesota Department of Commerce, Division of Energy Resources, September 2, 2014, p. 7.)[2] GMG agrees that utilizing a conservative approach when allocating a reserve margin is appropriate. GMG believes that maintaining its reserve margin at a conservative level continues to be prudent and has again utilized its portfolio in a manner that allows its reserve margin to be maintained without undue cost burdening its ratepayers. Therefore, GMG proposes a reserve margin of 10.3% for the upcoming heating season.

GMG's predictive modeling calculations reflect a need for a change in its design day entitlement. The table below summarizes GMG's design day and reserve calculations:

Existing Customer Base		
Design Day Requirement (Attachment A, Page 2 of 3, line 11)	11,336	Dth
Reserve at 10.3%	1,173	Dth
Design Day Requirement With 10.3% Reserve Margin	12,509	Dth

The ultimate objective of a design day analysis is to forecast anticipated firm customer demand at design temperatures to predict the necessary level of firm resources to sufficiently serve customer in the unlikely event that design day weather occurs. In order to meet that objective, a small increase in GMG's contract demand entitlement is warranted.

2. GMG's Design Day Analysis Ensures Viable Forecasting Given Available Customer Data and Predictive Information.

GMG's current design day projection is based on a single econometric model to forecast its supply needs for the upcoming heating season, relying on historic and recent quantitative data for its current season analysis.

GMG employed an ordinary least square regression analysis methodology to predict peak day demand, as it has done for several years. GMG's regression analysis is predicated on a 90 heating degree day as its basis, based on an average design day temperature of -25°F. GMG's design day forecast for its existing customers for the 2015-2016 heating season is based on 11,336 Dth, which is an increase of 2,367 Dth over the 2014-2015 design day requirements. The derivation of the design day forecast can be seen in Attachment A, Page 2 of 3.[3]

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2 . The Department did not comment on GMG's Amendment to its Petition occasioned by the Viking open season contract addition and the resulting increase in the reserve level for February, 2015-March, 2015.

3 . GMG again based its regression analysis on combined customer classes. Since the bulk of GMG's commercial customers were only recently acquired, there is still not a sufficient amount

GMG notes that the Department continued to express concern about GMG's use of negative baseload (non-heat sensitive load) in its regression analysis. (Docket No. G022/M-14-651, Comments of the Minnesota Department of Commerce, Division of Energy Resources, September 2, 2014, p. 3.) As GMG explained in its petition in that docket, GMG utilized regression analysis modeling consistent with its prior modeling because, since GMG's expanded system only began serving a large percentage of its customers in late 2013, GMG does not have sufficient historical data on which to base a summer usage estimate. Accordingly, GMG respectfully renews its request that it be permitted to continue utilizing its current methodology until it has three solid years of data upon which to calculate viable baseload consumption estimates. GMG recognizes that the practice likely results in a more conservative reserve amount; but, in light of the Commission's desire for a conservative reserve supply for GMG and the minimal overall rate impact on customers, GMG believes that it is most appropriate at this time in order to ensure a sufficient reserve.

Additionally, in reviewing the available historical information used for modeling input, GMG noted that the winter months of November, 2011 through March, 2012 were much warmer than normal, presenting a weather anomaly. When GMG removed those months from its calculation, the regression analysis did not result in any negative baseload. Interestingly, the difference in the resulting design day calculation was only 7 Dth. In the interest of providing consistent comparative data, GMG included historical data from November, 2011 in its current analysis. While GMG theoretically concurs with the Department's suggested approach, the actual difference in the design day calculation is statistically negligible given the increased amount of historical data available for the current forecasting.

Attachment A details the regression analysis calculations upon which GMG's contract demand entitlement petition is based, insofar as it relates to its existing customers and quantitative historical data. In conducting its least square regression analysis, GMG employed the following methodology:

> The analysis was completed by using historical firm sales volume data and actual temperature data for the heating season periods from November 2011 through February 2015. The firm sales volume data was correlated to geographic weather data by assigning town border station locations geographically to weather sites as follows:

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of historical data to separate residential and commercial classes for regression purposes, in that most have only two years or less of usage data. GMG is mindful of the Department's preference for separating its customer classes for regression analysis purposes; and, it intends to do so at such time as there is sufficient historical data available to provide meaningful analysis.

Weather Site	TBS Location
Mankato	Rapidan
Mankato	Madison Links
Faribault	Heidelberg
Faribault	Forest
Faribault	Faribault 5
Shakopee	Marystown
Randall	Alexandria

Employing widely-accepted statistical analysis, a linear equation was derived from the linear regression model that was used to calculate the design day usage per customer. The forecasted number of firm customers for the 2015-2016 heating season was then multiplied by the design day usage per customer to derive the design day requirements.

The linear regression models the linear relationship between heating degree day data and firm customer natural gas usage by fitting a linear equation to observed data. The linear regression line has an equation of the form:

$$\boldsymbol{Y = a + b\,X}$$

Where X (Heating Degree Days) is the explanatory variable and Y (Firm Sales Volume) is the dependent variable. The slope of the line is b, and a is the intercept (Firm Non-Temp Sensitive Volume).

The strength of the linear association is quantified by the correlation coefficient. The correlation coefficient takes a positive value between 0 and 1, with 1 indicating perfect correlation (all points would lay along a straight line in this case). A correlation value close to 0 indicates no association between the variables. The formula for computing the correlation coefficient is given by:

$$r = \frac{1}{n-1} \Sigma \left(\frac{x - \overline{x}}{s_x}\right)\left(\frac{y - \overline{y}}{s_y}\right)$$

The reliance on accepted statistical modeling methodology to obtain quantitative data for forecasting purposes is intended to mitigate discrepancies between actual resource utilization and planned supply needs. Hence, GMG has attempted to secure all available information to gauge likely customer sendout during a design day weather occurrence.

The Department observed that GMG's regression models have under-estimated consumption and suggested that GMG consider the reason for that result. (Docket No. G022/M-14-651, Comments of the Minnesota Department of Commerce, Division of Energy Resources, September 2, 2014, p. 4.) GMG believes that the most likely contributing factor is that its actual growth has exceeded its predicted growth level for the last several years. While GMG attempts to adequately predict growth, it does use a conservative approach. Empirical evidence suggests that, when GMG brings natural gas to a previously unserved area, many new customers ultimately avail themselves of the benefits that come with converting to gas use. Hence, actual throughput exceeds forecasted needs. That phenomena supports GMG's continued use of a conservative reserve margin. GMG considered a mathematical analysis based on actual throughput as the Department suggested. As shows in Attachment A, Page 3, GMG's peak day occurred on February 18, 2015 at 70 HDD and resulted in a firm sales throughput of 8,369 Dth/Day. The firm customer count on that date was 5,582, and the resulting use per customer was 1.430 Dth. GMG's customer additions for 2015 are projected to be 1747. GMG applied the following analysis:

90/70	(to adjust for 90 HDD)
x 8,369	actual peak day throughput
= 10,760	peak day if 90 HDD
+ 1,747	additional CEs based on residential usage of 1 Dth/Day
= 12,507	projected peak day requirement

GMG's analysis for additional customer equivalents is predicated on modeling peak day use of 1 Dth per day, which is consistent with the budget modeling that GMG employs. It is based on residential customer equivalents. GMG does not assume that actual customer additions will be a linear increase of its precise customer mix. GMG's mathematical analysis confirms that its requested demand entitlement will provide sufficient reserve.

3. The Summary of Winter Versus Summer Usage for All GMG Customer Classes Supports a Change in Demand Entitlement.

A summary of GMG's customer usage for both the winter and summer seasons is provided below, broken down by customer class. Due to the early filing of this Petition, the summary is based on usage for the twelve month period ending December 31, 2014.[4]

Balance of page intentionally left blank to accommodate table size.

[4] . GMG notes that previous demand entitlement dockets incorporated data for the twelve month period ending June 30th of the filing year. However, since this Petition is being submitted prior to June 30th, GMG utilized seasonal customer usage data for the 2014 calendar year.

Seasonal Customer Usage by Class (Dth)			
	Winter	**Summer**	**Total**
Residential - Firm	409,321	127,210	536,531
Commercial - Firm	13,711	4,600	18,311
Industrial - Firm	276,205	133,743	409,947
Flexible Rate - Firm	21,845	5,895	27,740
Total Firm	*721,081*	*271,448*	*992,529*
Agricultural - Interruptible	*62,847*	*10,428*	*73,275*
Industrial - Interruptible	27,259	1,522	28,781
Flexible Rate - Interruptible	1,776	43,699	45,475
Total Interruptible (Non-Ag)	*29,035*	*45,221*	*74,256*
Total	**812,963**	**327,097**	**1,140,060**

GMG's proposed increase in its contract demand entitlement will assure sufficient supply and reliability for its customers throughout the heating season. GMG's contract arrangements secure supply for both the summer months and the winter months to sufficiently serve its firm customer base throughout the year. GMG's proposal strikes the ideal balance for both cost and efficiency protections for its customers.

4. The Anticipated Design Day Gas Supply is in the Best Interest of Ratepayers Because it Provides for an Adequate Reserve Margin While Minimizing the Rate Impact.

GMG recognizes that the primary concerns of the Commission and the Department with regard to natural gas suppliers are sufficient assurance of reliability and reasonable rates for customers. It is critical that GMG is fully prepared to provide enough firm load to meet its customers' needs. In order to assure that it can meet all of its customers' needs throughout the year, GMG's proposal provides a balanced portfolio based on an integrated system. To that end, GMG has secured a variety of gas supply sources. A summary of GMG's demand profile shows the changes in GMG's supply sources, as compared to the supply sources for the two previous heating seasons, as seen in Attachment B. GMG is primarily served by the Northern Natural Gas and Viking Emerson pipeline systems. Attachment C identifies the contracts GMG holds with its sources; and, it also specifically notes proposed changes to its contracts for the 2015-2016 heating season and the corresponding change in contract demand costs.

GMG made two notable changes to its portfolio, both of which are reflected in GMG's illustrative PGA: securing additional capacity and securing storage.[5] First, as reflected in

[5] . GMG had a limited amount of time to secure the necessary capacity release and storage agreements. Since GMG had been thoroughly investigating alternative incremental capacity and storage options, GMG determined that the most prudent course of action was to secure the agreements. GMG met with Department and Commission staff prior to entering the agreements to advise staff of its plan and obtain any feedback that staff wished to offer. While GMG was

Attachment C, GMG contracted with Wisconsin Energy for 2600 Dth of non-recallable release capacity for a period of two years, running from November 1, 2015 through October 31, 2017. In November, 2014, GMG evaluated its needs for capacity and received quotes from Northern Natural Gas and ANR Pipeline. Northern Natural quoted its cost at $377 per year per Dth. Similarly, ANR quoted its cost at $331 per year per Dth. Viking did not have available capacity at that time that would meet GMG's needs. GMG explored alternative options and was able to obtain the contract with Wisconsin Energy at a cost of $68.87 per year per Dth, resulting in a savings of nearly 80% over the next-best option of the ANR capacity. Consequently, GMG contracted for the non-recallable release capacity to assure that it has adequate capacity to meet customer demand[6].

Second, GMG entered into a storage contract with BP. GMG has continued to be proactive in its approach to balancing its portfolio and acting in the best interests of its customers. GMG has historically had to rely on the daily gas market to meet customer needs. Early in 2014, GMG faced extremely high gas costs following the rupture of the TransCanada line. Essentially, the market impact of the rupture and resulting supply constraints was that transporters could demand high rates and distributors who were subject to daily market rates, like GMG, had no alternative but to pay the inflated rates in order to secure gas for customers. Market rates have continued to be volatile in light of pipeline disruptions and market variations. In order to insulate its customers from similar future price volatility, GMG secured the agreement for gas storage to alleviate the need to purchase swing supply on the daily market. The contract entails prepayment for gas based on the summer MichCon index with an injection period beginning April 1, 2015. GMG's withdrawal rights begin on November 1, 2015; and, BP will deliver the gas into the Viking line during the winter months based on GMG's demand. By acquiring gas during the summer months and storing it for future use, GMG will reduce its reliance on daily market swing supply, thereby shielding its customers from daily market fluctuations. GMG estimates that, had the storage been an option during the last heating season, GMG's customers would have saved between $650,000 and $993,000 during the January, 2014 to March, 2014 period following the TransCanada rupture.

GMG respectfully requests that the Commission approve inclusion of the demand charge for the storage agreement in its Purchased Gas Adjustment effective November 1, 2015; and GMG will include the charge in its PGA pending Commission approval. GMG notes that during its discussion with Department and Commission staff, the staff inquired about whether some portion of the storage cost should be allocated to GMG's interruptible customers. GMG carefully considered the most equitable means to allocate the storage cost and ultimately determined that nothing should be allocated to its interruptible customers. All but three of GMG's interruptible customers are agricultural grain dryers or industrial asphalt plants, neither

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aware that staff could not assure approval of the agreements, GMG values staff input and appreciates the staff's willingness to engage in preliminary, non-binding dialogue regarding the agreements.

[6] . GMG's contract with BP for delivery of 950 Dth expires in April, 2015; and, BP did not have the transportation capacity to renew that agreement.

of which operates during the winter months. Therefore, GMG determined that it is not appropriate to allocate a portion of the storage costs to the interruptible customers because they will not be using gas at the time that the gas is withdrawn from storage.

GMG recognizes that including the cost of the storage in the demand charge creates a substantial increase in the demand charge component of the total cost of gas. However, a thorough examination of the total economic impact of the storage option on the overall total cost of gas demonstrates that, while the demand charge component reflects an increase, substantial benefit inures to GMG's customers. The fluctuation in daily spot gas prices between January, 2014 and March, 2014 is illustrated by the graph contained in Attachment E, Page 1. Similarly, the chart in Attachment E, Page 2 shows the volatility in daily gas prices in February, 2015. Since GMG will be purchasing gas at summer rates and storing it, GMG will avoid significant winter gas costs and GMG's commodity cost component in expected to decrease substantially. While it is impossible to predict actual market trends in daily gas prices, GMG has assumed a 1 for 1 reduction in its estimated savings. GMG anticipates that this is the minimum amount that its customers will save and, depending on the actual market cost of daily gas through the winter months, the benefit to customers could even be higher. As a result, the decreased commodity cost benefit of the storage contract offsets the increased demand cost from the storage contract, resulting in a .86%, or $3.57, annual rate impact on the total cost of gas for GMG's firm customers.

While GMG's early submission of its Petition herein allows for substantial time to consider its request prior to the heating season, it also necessarily requires GMG to engage in prediction regarding both anticipated customer usage and anticipated customer growth for the remainder of the current year. As such, GMG intends to analyze its demand entitlement needs as the 2015-2016 heating season nears, essentially to true-up its anticipated needs and make any necessary demand adjustments at that time. .

GMG's supply contract scheme is designed so that gas can be delivered to alternate points and can be used elsewhere in GMG's integrated system if necessary at any given time. Thus, GMG has the ability to move supply throughout its service area on a day to day basis as market demand and supply options dictate.

Attachment D provides a summary of the rate impact to firm customers with the contract changes. It demonstrates that GMG's customers will not be subject to substantially increased rates because of the increased reserve. Therefore, there is no significant adverse impact to customer rates as a result of the increased demand entitlement, which further supports its approval.

REQUEST FOR COMMISSION ACTION

GMG's proposed change in contract demand entitlement serves the best interest of its customers. As the supporting information demonstrates, GMG coordinated its gas-supply planning for the 2015-2016 heating season alongside consideration of previous Department and Commission concerns and recommendations and its broader corporate planning. GMG's proposal strikes the appropriate balance between assuring physical reliability with sufficient supply to serve all customers in the event that design day weather occurs with minimizing the rate impact of maintaining a sufficient reserve on GMG customers. Therefore, GMG respectfully requests that the Commission approve its Petition for Change in Contract Demand Entitlement for the 2015-2016 Heating Season.

Dated: March 25, 2015

Respectfully submitted,

/s/

Kristine A. Anderson
Corporate Attorney
Greater Minnesota Gas, Inc.
202 S. Main Street
Le Sueur, MN 56068
Phone: 888-931-3411

ATTACHMENT A
Design Day Regression Analysis Background Information

Greater Minnesota Gas, Inc.
Contract Demand Entitlement Filing 2015 - 2016 Heating Season
Design Day Information

	Number of Sales Firm Customers			Design Day Requirement			Total Entitlement + Storage + Peak Shaving			Reserve Margin
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Heating Season	Number of Customers	Change from Pervious Year	% Change from Previous Year	Design Day (Dth)	Change from Pervious Year	% Change from Previous Year	Total Entitlement (Dth) 1/	Change from Pervious Year	% Change from Previous Year	% of Reserve Margin [(7)-(4)]/(4)]
2015-2016 Est (1/31)	7,740	1,888	32.26%	11,336	2,367	26.39%	12,509	2,850	29.51%	10.35%
2014-2015 (2/18)	5,852	547	10.31%	8,969	904	11.21%	9,659	300	3.21%	7.69%
2013-2014 (1/6)	5,305	531	11.12%	8,065	3,101	62.47%	9,359	4,150	79.67%	16.04%
2012-2013 (1/31)	4,774	558	13.24%	4,964	273	5.83%	5,209	165	3.27%	4.94%
2011-2012 (1/19)	4,216	319	8.19%	4,691	241	5.41%	5,044	-	0.00%	7.54%
2010-2011 (1/11)	3,897	175	4.70%	4,450 2/	239	5.66%	5,044	500	11.00%	13.35%
2009-2010 (1/10)	3,722	162	4.55%	4,211	(71)	-1.65%	4,544	300	7.07%	7.90%
2008-2009 (1/09)	3,560	182	5.39%	4,282	566	15.23%	4,244 3/	244	6.10%	-0.89%
2007-2008 (1/08)	3,378	170	5.30%	3,716	166	4.68%	4,000	350	9.59%	7.64%
2006-2007 (2/07)	3,208	237	7.98%	3,550	583	19.65%	3,650	350	10.61%	2.82%
2005-2006 (2/06)	2,971	290	10.82%	2,967	271	10.05%	3,300	300	10.00%	11.22%
2004-2005	2,681	336	14.33%	2,696	696	34.80%	3,000	600	25.00%	11.28%
2003-2004	2,345	181	8.36%	2,000	(200)	-9.09%	2,400	(200)	-7.69%	20.00%
2002-2003	2,164	300	16.09%	2,200	400	22.22%	2,600	400	18.18%	18.18%
2001-2002	1,864	301	19.26%	1,800	400	28.57%	2,200	500	29.41%	22.22%
2000-2001	1,563	393	33.59%	1,400	300	27.27%	1,700	300	21.43%	21.43%
1999-2000	1,170	279	31.31%	1,100	250	29.41%	1,400	150	12.00%	27.27%
1998-1999	891	289	48.01%	850	350	70.00%	1,250	750	150.00%	47.06%
1997-1998	602	339	128.90%	500	200	66.67%	500	200	66.67%	0.00%
1996-1997	263	263		300	300		300	300		
Average per Year:	2,406	264	23.12%	2,545	293	21.93%	2,824	315	24.62%	14.47%

	Firm Peak Day Send out						
	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Heating Season	Firm Peak Day Send out (Dth)	Change from Pervious Year	% Change from Previous Year	Excess per Customer [(7)-(4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak Day Send out per Customer (11)/(1)
2015-2016	Unknown			0.152	1.4646	1.6161	Unknown
2014-2015	8,369	489	6.21%	0.118	1.5326	1.6505	1.4301
2013-2014	7,880	2,855	56.82%	0.244	1.5203	1.7642	1.4854
2012-2013	5,025	1,368	37.41%	0.051	1.0398	1.0911	1.0526
2011-2012	3,657	(248)	-6.35%	0.084	1.1126	1.1964	0.8674
2010-2011	3,905	251	6.87%	0.152	1.1419	1.2943	1.0021
2009-2010	3,654	(374)	-9.29%	0.089	1.1315	1.2208	0.9817
2008-2009	4,028	(72)	-1.75%	(0.011)	1.2028	1.1921	1.1315
2007-2008	4,100	550	15.49%	0.084	1.1001	1.1841	1.2137
2006-2007	3,550	738	26.24%	0.031	1.1066	1.1378	1.1066
2005-2006	2,812	285	11.28%	0.112	0.9987	1.1107	0.9465
2004-2005	2,527	185	7.90%	0.113	1.0056	1.1190	0.9426
2003-2004	2,342	587	33.45%	0.171	0.8529	1.0235	0.9987
2002-2003	1,755	747	74.11%	0.185	1.0166	1.2015	0.8110
2001-2002	1,008	(180)	-15.15%	0.215	0.9657	1.1803	0.5408
2000-2001	1,188	291	32.44%	0.192	0.8957	1.0877	0.7601
1999-2000	897	95	11.85%	0.256	0.9402	1.1966	0.7667
1998-1999	802	397	98.02%	0.449	0.9540	1.4029	0.9001
1997-1998	405	233	135.47%	-	0.8306	0.8306	0.6728
1996-1997	172	172		-	1.1407	1.1407	0.6540
Average per Year:	2,210	260	30.50%	0.133	1.0248	1.1574	0.8953

Notes:
1/ Total Entitlement = Total Contract Entitlement - Non-Recallable Capacity Release
2/ Reflects design day forecast method change to linear regression model.
3/ Adjusted to reflect 300 Dth not contracted as originally planned in Docket No. G022/M-08-1327.
4/ Reflects extraordinary send out due to temporary construction heat load.

Greater Minnesota Gas, Inc.
Design Day: Heating Season 2015 - 2016
Derivation of Design Day Use Per Customer

Linear Regression Analysis Period: November thru March 2011-2014 & November 2014 thru February 2015

Line No.	Town Border Station(s)	Weather Area	Non- Heat Sensitive (Y Intercept)	Use Per HDD (Slope)	Design HDD	Estimated Design Dths	Regression Coefficient	Equation
1	Rapidan and Madison Links	Mankato	14.51	18.26	90	1,658	0.8682	Y Inter + Slope x Design HDD = Estimated Design Dth
2	Forest, Heidelberg, and Faribault 5	Faribault	-181.13	48.14	90	4,152	0.8051	
3	Marystown	Shakopee	-1.75	7.37	90	661	0.9175	
4	Randall	Alexandria	489.73	19.00	90	2,200	0.6964	
			321.35	92.77				
5				**Total Design Dths**		**8,671**		
6			**Estimated Interruptible Load**			**100**		
7				**Net Design Dths**		**8,571**		Line 4 - Line 5
8				**Customer Count 12/2014**		**5,852**		
9				**Design Dths/Customer**		**1.4646**		Line 6 / Line 7
10		**Estimated Firm Customers for 2015/2016**				**7,740**	*	
11				**Design Dths 2015/2016**		**11,336**		Line 8 x Line 9

* Excludes individual identified commercial customer loads

Greater Minnesota Gas, Inc.
Peak Day Analysis

Line No.	Description	Design Day Calculation	Peak Day 2014 -15	Peak Day 2013 -14	Peak Day 2012 -13	Peak Day 2011 -12
1	Date of Peak Day		18-Feb-15	6-Jan-14	31-Jan-13	19-Jan-12
2	Day of the Week		Wednesday	Monday	Thursday	Thursday
3	Total Throughput (Dth)	11436	8464	7895	5038	3710
4	Interruptible Customer Usage (Dth)	100	95	15	13	53
5	Firm Transportation Usage (Dth)	0	0	150	150	132
6	Firm Sales Throughput (Dth)	11336	8369	7730	4875	3525
7	Average Actual Gas Day Temperature (Deg. F)	-25	-5	-17	-1	-3
8	Heating Degree Days (HDD) 65 degree base	90	70	82	66	68
9	Non-HDD Sensitive Base (Dth)	321	321	180	-92	301
10	Total HDD Sensitive Firm Throughput (Dth)	11015	8048	7550	4967	3224
11	Actual Firm Peak Day Dth/HDD (Dth)	122	115	92	75	47
12	Base + (Actual Dth/HDD * HDDs) (Dth)	11336	8369	7730	4875	3525
13	Peak Month Firm Customers	7740	5852	5305	4774	4216
14	Peak Day Use per Firm Customer	1.465	1.430	1.457	1.021	0.836
			Sales Feb '15	% of Total		
15	Firm Sales					
16	Residential		80,213	47.5%		
17	Commercial		13,693	8.1%		
18	Industrial		70,553	41.8%		
19	Flexible Rate Industrial		4,340	2.6%		
20	Total Firm Sales		168,798	100.0%		
21	Allocated Peak Day based on Dth Sales					
22	Residential	5,387	3,977	47.5%		
23	Commercial	920	679	8.1%		
24	Industrial	4,738	3,498	41.8%		
25	Flexible Rate Industrial	291	215	2.6%		
26	Total Firm Sales	11,336	8,369	100%		

ATTACHMENT B
Demand Profile and Supply Comparison

Greater Minnesota Gas, Inc.
Contract Demand Entitlement Filing
Demand Profile

2013 - 2014 Heating Season (revised)	Quantity (Dth)		2014 - 2015 Heating Season	Quantity (Dth)	Change in Quantity (Dth)		2015 - 2016 Heating Season	Quantity (Dth)	Change in Quantity (Dth)
TF-7 (Summer - Apr. - Oct.)	**-**		**TF-7 (Summer - Apr. - Oct.)**	**-**	**-**		**TF-7 (Summer - Apr. - Oct.)**	**-**	**-**
TF 12 (Nov. - Oct.)	**210**		**TF 12 (Nov. - Oct.)**	**210**	**-**		**TF 12 (Nov. - Oct.)**	**210**	**-**
TFX-7 (Oct. - Apr.))	**665**		**TFX-7 (Oct. - Apr.))**	**665**	**-**		**TFX-7 (Oct. - Apr.))**	**665**	**-**
TFX-5 (Nov. - Mar.)	**6,344**		**TFX-5 (Nov. - Mar.)**	**6,344**	**-**		**TFX-5 (Nov. - Mar.)**	**6,344**	**-**
Viking Zone 1	2,000	**(2)**	Viking Zone 1	2,000	**-**	**(2)**	Viking Zone 1	2,000	**-**
TFX-5 (Nov. - Mar.)	**90**		**TFX-5 (Nov. - Mar.)**	**90**	**-**		**TFX-5 (Nov. - Mar.)**	**90**	**-**
Viking Forward Haul/Emerson	**1,300**	**(3)**	**Viking Forward Haul/Emerson**	**1,400**	**100**	**(3)**	**Viking Forward Haul/Emerson**	**1,400**	**-**
Delivery Contract	**950**	**(4)**	**Delivery Contract**	**950**	**-**	**(4)**	**Delivery Contract**	**-**	**(950)**
Capacity Release - Non-recallable	**-**		**Capacity Release - Non-recallable**	**-**	**-**		**FT-A Capacity Release - Non-recallabl**	**2,600**	**2,600**
		(5)	TFX-1 (Purchased Oct. 2014)	1,000		**(5)**	TFX-1 (Purchased Oct. 2014)	-	
		(6)	**Viking Forward Haul/Emerson**	**1,200**	**1,200**	**(6)**	**Viking Forward Haul/Emerson**	**1,200**	**-**
SMS	1,300		SMS	2,000	**700**		SMS	2,000	**-**
Heating Season Total Capacity	9,559		Heating Season Total Capacity	10,859	1,300		Heating Season Total Capacity	12,509	1,650
Non-Heating Season Total Capacity	210		Non-Heating Season Total Capacity	210	-		Non-Heating Season Total Capacity	210	-
Total Entitlement @ Peak	9,559		Total Entitlement @ Peak	10,859	1,300		Total Entitlement @ Peak	12,509	1,650
Total Annual Transportation	-		Total Annual Transportation	-	-		Total Annual Transportation	-	-
Total Season Transportation	9,559		Total Season Transportation	10,859	1,300		Total Season Transportation	12,509	1,650
Total Percent Summer Vs. Winter	2.2%		Total Percent Summer Vs. Winter	1.9%			Total Percent Summer Vs. Winter	1.7%	
Total Percent Seasonal	100.0%		Total Percent Seasonal	100.0%			Total Percent Seasonal	100.0%	

Notes:

1/ Only items in bold affect capacity entitlement level.

2/ Transport only. Does not increase peak day entitlement.

3/ 1,400 Dth disrupted in October, 2014 only due to Viking Force Majeur

4/ Company has contract for supply delivered to TBS. No demand Charges are applicable, but the 950Dth's are available on peak day.

5/ 1,000 Dth of TFX purchased for October, 2014 only to replace capacity loss due to Viking's Force Majeur. Does not affect peak day entitlement.

6/ 1,200 Dth of FT-A purchased during Viking open season beginning February 1, 2015.

ATTACHMENT C
Contract Entitlement Changes

Greater Minnesota Gas, Inc.
Natural Gas Contract Summary
Contract Entitlement Changes as of April 1, 2015

Contract Entitlements 2014-15

	Contract No.	Service Type	Rate Schedule	Months	Entitlement (Dth)	Expiration Date
	102985	Firm Throughput	TFX - 5	Nov-Mar	3,000	3/31/2017
	102985	Firm Throughput	TFX - 5	Nov-Mar	500	3/31/2018
	102985	Firm Throughput	TFX - 5	Nov-Mar	500	3/31/2019
	102985	Firm Throughput	TFX - 5	Nov-Mar	2,100	3/31/2020
	102985	Firm Throughput	TFX - 5	Nov-Mar	244	3/31/2020
	121534	Firm Throughput	TFX - 7	Oct-Apr	665	10/31/2020
	120579	Firm Throughput	TF - 12	Oct-Sep	181	9/30/2017
	120579	Firm Throughput	TF - 12	Oct-Sep	29	9/30/2017
	120579	Firm Throughput	TFX - 5	Nov-Mar	90	9/30/2017
	127955	Firm Throughput	TF-11	Oct 2014 only		10/31/2014
	BP Contract	Contracted Delivery		Nov-Sep	950	4/30/2015
	Viking Emerson	Forward Haul	TF-12	Nov-Oct	1,400	10/31/2018
	Viking Emerson	Forward Haul	FT-A	Feb-Oct	1,200	1/31/2026
			2014-15 Heating Season Total Capacity		10,859	
			2014-15 Design Day Demand		8,969	
			Reserve Margin		1,890	21.1%

Proposed Contract Entitlement Changes for 2015-16

Start Date	Contract No.	Service Type	Rate Schedule	Months	Entitlement (Dth)	Expiration Date
	BP Contract	Contracted Delivery	N/A	Nov-Sep	(950)	4/30/2015
	Viking RF1358	VGT WI Gas Release	FT-A	Nov-Oct	2,600	10/31/2017
			2015-16 Heating Season Total Capacity		12,509	
			2015-16 Design Day Demand		11,336	
			Reserve Margin		1,173	10.3%

Proposed Change in Contract Demand Costs

Contract No.	Rate Schedule	Volume Dth / Day	No. of Months	Monthly Demand Rates	Total Annual Cost
Viking Emerson	N/A	(950)		$ -	$ -
Viking RF1358	FT-A	2,600	12	$ 5.7394	$ 179,069.28
					$ 179,069.28

ATTACHMENT D
Rate Impact of Proposed Contract Demand Entitlement

Greater Minnesota Gas, Inc.
Contract Demand Entitlement Filing
Rate Impact - November 2015

	Annualized Impact									
Residential	Last Rate Case 1/	Last Demand Change 2/	Current PGA w/o Demand Ent. Change (Mar. 1, 2015)	Proposed Demand Entitlement Change	Change from Last Rate Case	% Change from Last Rate Case	Change from Last Demand Change	% Change from Last Demand Change	Change from Most Recent PGA	% Change from Most Recent PGA
Commodity Cost of Gas (WACOG)	$ 5.8801	$ 3.5739	$ 3.5739	$ 3.2410	$ (2.6392)	-44.88%	$ (0.3329)	-9.32%	$ (0.3329)	-9.32%
Demand Cost of Gas	$ 0.8293	$ 0.8435	$ 0.8435	$ 1.2143	$ 0.3850	46.42%	$ 0.3708	43.97%	$ 0.3708	43.97%
Total Cost of Gas	$ 6.7094	$ 4.4174	$ 4.4174	$ 4.4553	$ (2.2542)	-33.60%	$ 0.0379	0.86%	$ 0.0379	0.86%
Average Annual Usage (Dth)	94.1	94.1	94.1	94.1						
Average Annual Total Cost of Gas	$ 631.55	$ 415.80	$ 415.80	$ 419.37	$ (212.18)	-33.60%	$ 3.57	0.86%	$ 3.57	0.86%

	Annualized Impact									
Commercial & Industrial Firm	Last Rate Case 1/	Last Demand Change 2/	Current PGA w/o Demand Ent. Change (Mar. 1, 2015)	Proposed Demand Entitlement Change	Change from Last Rate Case	% Change from Last Rate Case	Change from Last Demand Change	% Change from Last Demand Change	Change from Most Recent PGA	% Change from Most Recent PGA
Commodity Cost of Gas (WACOG)	$ 5.8801	$ 3.5739	$ 3.5739	$ 3.2410	$ (2.64)	-44.88%	$ (0.3329)	-9.32%	$ (0.3329)	-9.32%
Demand Cost of Gas	$ 0.8293	$ 0.8435	$ 0.8435	$ 1.2143	$ 0.38	46.42%	$ 0.3708	43.97%	$ 0.3708	43.97%
Total Cost of Gas	$ 6.7094	$ 4.4174	$ 4.4174	$ 4.4553	$ (2.25)	-33.60%	$ 0.0379	0.86%	$ 0.0379	0.86%
Average Annual Usage (Dth)	3,352.9	3,352.9	3,352.9	3,352.9						
Average Annual Total Cost of Gas	$ 22,496.20	$ 14,811.05	$ 14,811.05	$ 14,938.16	$ (7,558.03)	-33.60%	$ 127.11	0.86%	$ 127.11	0.86%

Notes:
1/ Docket Nos. G022/GR-09-962 & G022/MR-10-949
2/ Docket No. G022/M-10-1165 & G022/AA-10-1186

Greater Minnesota Gas, Inc.
Purchased Gas Adjustment (PGA) Calculation

Effective date of implementation: Natural gas usage on and after **March 1, 2015**

Reason for change: Change in cost of gas due to an estimated Increase in the market price of natural gas from February 2015.

This PGA is based on the following Northern Natural Gas Tariffs:
7th Revised Sheet No. 50
Issued: 1/31/14
Effective: 4/1/14
8th Revised Sheet No. 51
Issued: 12/04/14
Effective: 01/06/2015
1st Revised Sheet No. 55
Issued: 6/30/14
Effective: 9/30/14

This PGA is based on the following Viking Gas Transmission Co. Tariffs:
v.21.0.0 superseding v.20.0.0
Issued: 11/14/14
Effective: 01/01/15

I. Greater Minnesota Gas, Inc. - Base Cost of Gas **November 1, 2010**
Approved in Docket No. G022/MR-10-949

		MCF	x Months	x Tariff Rate	Equals	Rate/CCF Firm	Rate/CCF Interruptible
All Customer Sales Rate Classes - Demand							
	TFX - 7	300	7	$5.6830	11,934	$0.002773	
	TFX-5	4,244	5	$15.1530	321,547	$0.074711	
	SMS Demand	50	7	$2.1800	763	$0.000177	
		1,300	8	$2.1800	22,672	$0.005268	
	Total Capacity Cost				$356,916		
	Rate Case 2009 Firm Sales Service Volume - CCF			4,303,890			
	Demand Base Cost of Gas / CCF					**$0.082929**	**$0.000000**
All Customer Sales Rate Classes - Commodity							
	All Classes Commodity				$ 2,808,142		
	Rate Case Total Sales Service Volume - CCF			4,775,650			
	Commodity Base Cost of Gas/CCF					**$0.588013**	**$0.588013**
	Total Base Cost of Gas/CCF				$3,165,058	**$0.670942**	**$0.588013**

Annual Sales Volume - 2009 Rate Case Sales Service Volume - CCF		**4,775,650**
Sales Service Volume - CCF	4,303,890	
Interruptible Service Volume - CCF	471,760	

II. Greater Minnesota Gas, Inc. Rates - Current Cost of Gas Effective **March 1, 2015**

Commodity Cost of Gas $0.357390 WACOG

III. Annual Sales Volume - 2014-2015 Budget (September - August)		**10,723,750**
Sales Service Volume - CCF	**9,433,900**	
Interruptible Service Volume - CCF	**1,289,850**	

IV. Greater Minnesota Gas, Inc.'s -- Current Cost of Gas Effective **March 1, 2015**

All Customer Sales Rate Classes		MCF	x Months	x Tariff Rate		Equals	Rate/CCF Firm	Rate/CCF Ag Interr	Rate/CCF Gen Interr
	Viking Zone 1	2,000	12	$4.3706		104,894	$0.011119		
	Viking Zone 1	1,400	12	$4.3706		73,426	$0.007783		
	Viking Zone 1	1,200	9	$4.3706		47,202	$0.005003		
	TFX - 5	6,344	5	$15.1530		480,653	$0.050950		
	TF - 12	181	5	$10.2300		9,258	$0.000981		
	TF - 12	181	7	$5.6830		7,200	$0.000763		
	TF - 12	29	5	$10.2300		1,483	$0.000157		
	TF - 12	29	7	$5.6830		1,154	$0.000122		
	TF - 5	90	5	$15.1530		6,819	$0.000723		
	TFX - 7	665	5	$15.1530		50,384	$0.005341		
	TFX - 7	665	2	$5.6830		7,558	$0.000801		
	TFX	1,000	1	$5.6830		5,683	$0.000602		
						0	$0.000000		
	Current Demand Cost of Gas					$795,716	**$0.084345**	**$0.000000**	**$0.000000**
	Current Commodity Cost of Gas/CCF			% of Total	83%	**$3,832,561**	**$0.357390**	**$0.357390**	**$0.357390**
	Total Cost of Gas/CCF					**$4,628,277**	**$0.441735**	**$0.357390**	**$0.357390**

Summary of Cost

All Customer Sales Rate Classes (/CCF)

	Firm Sales				Agricultural Interruptible				General Interruptible			
	Total Demand	Total Commodity	True-up	**Total**	Total Demand	Total Commodity	True-up	**Total**	Total Demand	Total Commodity	True-up	**Total**
1) Base Rate	$0.082929	$0.588013	$0.000000	**$0.670942**	$0.000000	$0.588013	$0.000000	**$0.588013**	$0.000000	$0.588013	$0.000000	**$0.588013**
2) Prior PGA	($0.003587)	($0.250423)	$0.003640	**($0.250370)**	$0.000000	($0.250423)	($0.009730)	**($0.260153)**	$0.000000	($0.250423)	($0.003190)	**($0.253613)**
3) Current Adj	$0.005003	$0.019800	$0.000000	**$0.024803**	$0.000000	$0.019800	$0.000000	**$0.019800**	$0.000000	$0.019800	$0.000000	**$0.019800**
4) PGA Billed (2+3)	$0.001416	($0.230623)	$0.003640	**($0.225567)**	$0.000000	($0.230623)	($0.009730)	**($0.240353)**	$0.000000	($0.230623)	($0.003190)	**($0.233813)**
5) Average Cost of Gas	$0.084345	$0.357390	$0.003640	**$0.445375**	$0.000000	$0.357390	($0.009730)	**$0.347660**	$0.000000	$0.357390	($0.003190)	**$0.354200**

	Prior Cumulative Adjustments	Demand & Commodity Change Filed Herein	True-up Adjustment Factor Change Eff. September 1, 2014 (G022/AA-14-___)	Current PGA Adjustment
All Firm Sales Rate Classes (/CCF)	($0.254010)	$0.024803	$0.003640	**($0.225567)**
Ag Inter. Sales Rate Classes (/CCF)	($0.250423)	$0.019800	($0.009730)	**($0.240353)**
Gen. Inter. Sales Rate Classes (/CCF)	($0.250423)	$0.019800	($0.003190)	**($0.233813)**

March 1, 2015		1	2	3	4	5	7
Rate Class	Tariff Rate Designation	Non-gas Commodity Margin ($/CCF)	Commodity Cost ($/CCF)	Demand Other PGA Expenses ($/CCF)	Total Cost of Gas ($/CCF) (2)+(3)+(4)	True-up Factor ($/CCF)	Total Billing Rate ($/CCF)
Residential	RS1	$0.444330	$0.357390	$0.084345	$0.441735	$0.003640	$0.889705
Small Commercial CS1	SCS1	$0.426330	$0.357390	$0.084345	$0.441735	$0.003640	$0.871705
Commercial CS1	CS1	$0.396330	$0.357390	$0.084345	$0.441735	$0.003640	$0.841705
Commercial/Industrial MS1	MS1	$0.376330	$0.357390	$0.084345	$0.441735	$0.003640	$0.821705
Commercial/Industrial LS1	LS1	$0.361330	$0.357390	$0.084345	$0.441735	$0.003640	$0.806705
Agricultural - Interruptible	AG1	$0.231310	$0.357390	$0.000000	$0.357390	($0.009730)	$0.578970
General Interruptible	IND1	$0.251310	$0.357390	$0.000000	$0.357390	($0.003190)	$0.605510
General Interruptible - Flex	IND1 - FL	$0.030000	$0.357390	$0.000000	$0.357390	($0.003190)	$0.384200

Estimated Gas Volumes March 2015 1,348,400 Ccf

FOR ILLUSTRATIVE PURPOSES ONLY

Greater Minnesota Gas, Inc.
Purchased Gas Adjustment (PGA) Calculation

Effective date of implementation: Natural gas usage on and after **November 1, 2015**

This PGA is based on the following Northern Natural Gas Tariffs:	This PGA is based on the following Viking Gas Transmission Co. Tariffs:
7th Revised Sheet No. 50	v.21.0.0 superseding v.20.0.0
Issued: 1/31/14	Issued: 11/14/14
Effective: 4/1/14	Effective: 01/01/15
8th Revised Sheet No. 51	
Issued: 12/04/14	
Effective: 01/06/2015	
1st Revised Sheet No. 55	
Issued: 6/30/14	
Effective: 9/30/14	

I. Greater Minnesota Gas, Inc. - Base Cost of Gas **November 1, 2010**
Approved in Docket No. G022/MR-10-949

		MCF	x Months	x Tariff Rate	Equals	Rate/CCF Firm	Rate/CCF Interruptible
All Customer Sales Rate Classes - Demand							
	TFX - 7	300	7	$5.6830	11,934	$0.002773	
	TFX-5	4,244	5	$15.1530	321,547	$0.074711	
	SMS Demand	50	7	$2.1800	763	$0.000177	
		1,300	8	$2.1800	22,672	$0.005268	
	Total Capacity Cost				$356,916		
	Rate Case 2009 Firm Sales Service Volume - CCF			4,303,890			
	Demand Base Cost of Gas / CCF					**$0.082929**	**$0.000000**
All Customer Sales Rate Classes - Commodity							
	All Classes Commodity				$ 2,808,142		
	Rate Case Total Sales Service Volume - CCF			4,775,650			
	Commodity Base Cost of Gas/CCF					**$0.588013**	**$0.588013**
	Total Base Cost of Gas/CCF				$3,165,058	**$0.670942**	**$0.588013**

Annual Sales Volume - 2009 Rate Case Sales Service Volume - CCF		**4,775,650**
Sales Service Volume - CCF	4,303,890	
Interruptible Service Volume - CCF	471,760	

II. Greater Minnesota Gas, Inc. Rates - Current Cost of Gas Effective **November 1, 2015**

Commodity Cost of Gas	$0.324098	WACOG

III. Annual Sales Volume - 2015-2016 Budget (September - August) Adjusted for growth in sales for 2015-2016 **12,463,750**

Sales Service Volume - CCF	**11,173,900**
Interruptible Service Volume - CCF	**1,289,850**

IV. Greater Minnesota Gas, Inc.'s -- Current Cost of Gas Effective **November 1, 2015**

		MCF	x Months	x Tariff Rate		Equals	Rate/CCF Firm	Rate/CCF Ag Interr	Rate/CCF Gen Interr
All Customer Sales Rate Classes									
	Viking Zone 1	2,000	12	$4.3706		104,894	$0.009387		
	Viking Zone 1	1,400	12	$4.3706		73,426	$0.006571		
	Viking Zone 1	1,200	12	$4.3706		62,937	$0.005632		
	TFX - 5	6,344	5	$15.1530		480,653	$0.043016		
	TF - 12	181	5	$10.2300		9,258	$0.000829		
	TF - 12	181	7	$5.6830		7,200	$0.000644		
	TF - 12	29	5	$10.2300		1,483	$0.000133		
	TF - 12	29	7	$5.6830		1,154	$0.000103		
	TF - 5	90	5	$15.1530		6,819	$0.000610		
	TFX - 7	665	5	$15.1530		50,384	$0.004509		
	TFX - 7	665	2	$5.6830		7,558	$0.000676		
	FT-A	2,600	12	$5.7394		179,069	$0.016026		
	Storage Demand Charge	48,000	5	$1.5500		372,000	$0.033292		
	Current Demand Cost of Gas					$1,356,836	**$0.121428**	**$0.000000**	**$0.000000**
	Current Commodity Cost of Gas/CCF			% of Total	75%	**$4,039,476**	**$0.324098**	**$0.324098**	**$0.324098**
	Total Cost of Gas/CCF					**$5,396,312**	**$0.445526**	**$0.324098**	**$0.324098**

FOR ILLUSTRATIVE PURPOSES ONLY

Summary of Cost
All Customer Sales Rate Classes (/CCF)

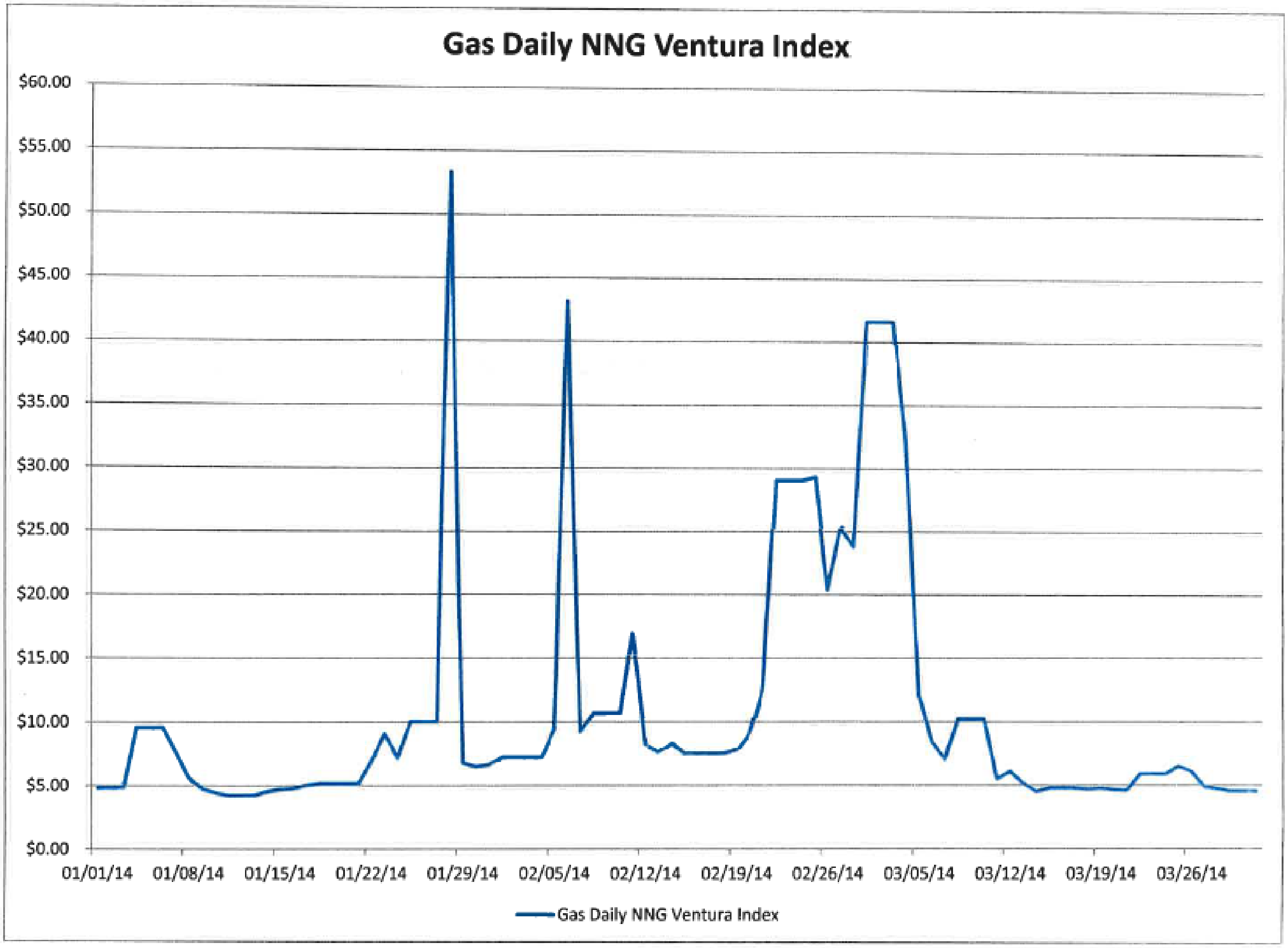
	Firm Sales				Agricultural Interruptible				General Interruptible			
	Total Demand	Total Commodity	True-up	**Total**	Total Demand	Total Commodity	True-up	**Total**	Total Demand	Total Commodity	True-up	**Total**
1) Base Rate	$0.082929	$0.588013	$0.000000	**$0.670942**	$0.000000	$0.588013	$0.000000	**$0.588013**	$0.000000	$0.588013	$0.000000	**$0.588013**
2) Prior PGA	($0.003587)	($0.250423)	$0.003640	**($0.250370)**	$0.000000	($0.250423)	($0.009730)	**($0.260153)**	$0.000000	($0.250423)	($0.003190)	**($0.253613)**
3) Current Adj	$0.042086	($0.013492)	$0.000000	**$0.028594**	$0.000000	($0.013492)	$0.000000	**($0.013492)**	$0.000000	($0.013492)	$0.000000	**($0.013492)**
4) PGA Billed (2+3)	$0.038499	($0.263915)	$0.003640	**($0.221776)**	$0.000000	($0.263915)	($0.009730)	**($0.273645)**	$0.000000	($0.263915)	($0.003190)	**($0.267105)**
5) Average Cost of Gas	$0.121428	$0.324098	$0.003640	**$0.449166**	$0.000000	$0.324098	($0.009730)	**$0.314368**	$0.000000	$0.324098	($0.003190)	**$0.320908**

	Prior Cumulative Adjustments	Demand & Commodity Change Filed Herein	True-up Adjustment Factor Change Eff. September 1, 2014 (G022/AA-14-___)	Current PGA Adjustment
All Firm Sales Rate Classes (/CCF)	($0.254010)	$0.028594	$0.003640	**($0.221776)**
Ag Inter. Sales Rate Classes (/CCF)	($0.250423)	($0.013492)	($0.009730)	**($0.273645)**
Gen. Inter. Sales Rate Classes (/CCF)	($0.250423)	($0.013492)	($0.003190)	**($0.267105)**

		1	2	3	4	5	7
November 1, 2015	Tariff	Non-gas	Commodity	Demand	Total Cost	True-up	Total
	Rate	Commodity	Cost	Other PGA	of Gas	Factor	Billing
	Designation	Margin	($/CCF)	Expenses	($/CCF)	($/CCF)	Rate
Rate Class		($/CCF)		($/CCF)	(2)+(3)+(4)		($/CCF)
Residential	RS1	$0.444330	$0.324098	$0.121428	$0.445526	$0.003640	$0.893496
Small Commercial CS1	SCS1	$0.426330	$0.324098	$0.121428	$0.445526	$0.003640	$0.875496
Commercial CS1	CS1	$0.396330	$0.324098	$0.121428	$0.445526	$0.003640	$0.845496
Commercial/Industrial MS1	MS1	$0.376330	$0.324098	$0.121428	$0.445526	$0.003640	$0.825496
Commercial/Industrial LS1	LS1	$0.361330	$0.324098	$0.121428	$0.445526	$0.003640	$0.810496
Agricultural - Interruptible	AG1	$0.231310	$0.324098	$0.000000	$0.324098	($0.009730)	$0.545678
General Interruptible	IND1	$0.251310	$0.324098	$0.000000	$0.324098	($0.003190)	$0.572218
General Interruptible - Flex	IND1 - FL	$0.030000	$0.324098	$0.000000	$0.324098	($0.003190)	$0.350908

ATTACHMENT E
Daily Gas Prices

January – March, 2014



February, 2015

Gas Price Index Report - Daily

	Gas Daily NNG Ventura Index
02/01/15	2.775
02/02/15	2.775
02/03/15	2.665
02/04/15	2.760
02/05/15	2.785
02/06/15	2.570
02/07/15	2.485
02/08/15	2.485
02/09/15	2.485
02/10/15	2.580
02/11/15	2.820
02/12/15	3.205
02/13/15	3.045
02/14/15	3.110
02/15/15	3.110
02/16/15	3.110
02/17/15	3.110
02/18/15	4.915
02/19/15	11.340
02/20/15	5.835
02/21/15	7.060
02/22/15	7.060
02/23/15	7.060
02/24/15	4.995
02/25/15	5.140
02/26/15	4.930
02/27/15	3.880
02/28/15	3.880
AVG	4.070
MAX	11.340
MIN	2.485