202 S. Main Street
Le Sueur, MN 56058
Toll Free: (888) 931-3411
Fax (507) 665-2588
www.greatermngas.com

August 19, 2013

VIA ELECTRONIC FILING

Dr. Burl W. Haar
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. ________________
PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

Dear Dr. Haar:

Attached hereto, please find Greater Minnesota Gas, Inc.'s Petition for Change in Contract Demand Entitlement for 2013-2014 Heating Season for filing in a new docket. The attached document is a public document and trade secret data has been excised. A complete copy including the redacted trade secret information has been filed with the Commission.

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

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

MPUC Docket No. ______________

PETITION FOR CHANGE IN CONTRACT DEMAND ENTITLEMENT FOR 2013-2014 HEATING SEASON	**PUBLIC DOCUMENT— TRADE SECRET DATA HAS BEEN EXCISED**

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, 2013. GMG will provisionally include the rate impact of these changes in GMG's Purchased Gas Adjustments effective November 1, 2013, pending Commission approval.

GMG's analysis demonstrates that with the proposed changes, GMG will have sufficient capacity to serve its firm customers during the 2013-2014 heating season. However, 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 that, when filing for a change in demand, GMG identify four things: a description 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 the new level. This Petition addresses each of the requisite four areas, based on GMG's analysis of its current customer usage and patterns, GMG's anticipated growth during the upcoming heating season, and forecasting the size and expected load of likely new customers.

DISCUSSION

GMG experienced substantial growth, well beyond that of GMG's anticipated growth level and goal, during the 2012-2013 heating season. GMG's growth has continued at a substantial rate, and the vast majority of GMG's new customers previously used alternate heating methods, making it difficult to obtain information for predictive purposes. In developing its contract demand entitlement proposal for the 2013-2014 heating season, GMG employed a combination of analytical tools in order 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, qualitative data from its new customers, projected growth information, and budget year analysis, GMG's proposed demand entitlement is soundly supported by both qualitative and quantitative data.

GMG seeks an increase in total demand entitlement as follows:

Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	% Change From Previous Year
5,209	9,359	4,150	79.67

1. **GMG Requires an Increase in Demand Due to Increased Growth, Which Results in a Design Day Change and Increased Requirements to Provide an Adequate Reserve Margin.**

An increased demand entitlement is required by GMG for two main reasons. First, GMG's growth during the previous heating season necessarily requires an increase in demand, simply to meet the needs of its recently acquired customers. Second, GMG's continued growth, which is anticipated to continue through the 2013-2014 heating season, will result in increased firm customer demand and, as a result, the need for increased firm capacity, both to meet customer's needs in the event that design day weather occurs and to maintain an adequate reserve margin.

GMG's proposal attempts to balance the necessity of a sufficient reserve margin with protection for its ratepayers from an unreasonable reserve cost. As the Department noted in its comments regarding a previous GMG petition for increased entitlement, the OES generally uses a gauge of five percent to determine the appropriateness of firm's reserve margin. Hence, GMG has predicated its demand entitlement request on striving for a five percent reserve margin[1]. As the

[1]. Historically, the Department has recommended a five percent reserve margin. In an effort to alleviate any concerns regarding GMG's current demand entitlement forecasting given its changing customer level, GMG met informally with Department analysts to discuss the feasibility of continuing to use a five percent reserve margin. GMG is comfortable with that reserve level, given its design day modeling as reflected herein and its commitment to reasonable customer rates; and, the analysts theoretically concurred. However, to the extent that the Commission feels that a higher reserve margin is necessary, or becomes necessary at the point of review, GMG's contract demand entitlement request will be adjusted accordingly.

Department previously noted, “The reserve margin is necessary since it provides an extra cushion which ensures firm reliability on a peak day; however, carrying too great a reserve margin results in customers paying higher demand costs than are necessary to provide reasonable service.” (Docket No. G022/M-10-1165, Comments of the Minnesota Office of Energy Security, January 3, 2011, p. 5.)

GMG’s increased customer base necessarily requires GMG to change its design day entitlement. The growth that GMG experienced since the last demand entitlement filing was greater than what was anticipated. Therefore, GMG’s customer needs increased and additional capacity is necessary to serve those currently existing customers. In addition, GMG projects continued growth for the upcoming heating season. Many of GMG’s new customers are commercial additions that have firm requirements. Hence, GMG needs to ensure sufficient capacity to meet the needs of its anticipated new customers for the upcoming heating season, as well. The result of such growth necessarily makes forecasting somewhat uncertain, as the Department previously observed, stating, “. . . since Greater Minnesota is a small utility, unexpected customer additions can have a significant impact on throughput.”
(Docket No. G022/M-10-1165, Comments of the Minnesota Office of Energy Security, January 3, 2011, p. 5.) Consequently, GMG’s increased customer base directly correlates to the need for an increase in its demand entitlement. The table below demonstrates the dramatic increase in GMG’s supply needs.

Existing Customer Base + Residential and Small Commercial Additions		
Design Day (Attachment B, Page 2 of 3, line 10)	5,858	Dth
Estimated Large Commercial Additions		
Project 1(Trade Secret)	642	Dth
Project 2 (Trade Secret)	2,417	Dth
Design Day Requirement	8,917	Dth
Reserve at 5%	446	Dth
Design Day Requirement With 5% Reserve Margin	9,363	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. As a result of the growth that GMG has undergone — and continues to undergo — its previous reserve entitlement will be insufficient for the coming season and an increase in GMG’s contract demand entitlement is warranted.

2. **GMG’s Design Day Analysis Aptly Employs Both Quantitative and Qualitative Data to Ensure Viable Forecasting Given Available Customer Data and Predictive Information.**

Although GMG has historically relied on a single econometric model to forecast its supply needs for each upcoming heating season, GMG’s growth and its new customer mix merits a different approach for current forecasting purposes. The combined quantitative and qualitative indicators permit consideration of all relevant factors to enable GMG to make prudent distribution system and peak capacity planning decisions in order to ensure satisfaction of firm customer demand on the coldest days. Hence, GMG made use of qualitative data for its anticipated new customers and combined that information with historical quantitative data for its existing customers.

a. Qualitative Information for New GMG Customers Provides a Basis for Extrapolation of Data for Enumerative Forecasting Purposes.

It is difficult to precisely predict the size and expected load of GMG's likely new customers, as the majority of them are transitioning from propane use to natural gas. As such, there is no accurate history of their load use. As GMG acquired new customers, it worked with customers to attempt to assess each customer's average propane load over the past three to four years. GMG then translated reported propane use to anticipated natural gas use, estimating propane use at 91,500 BTUs per gallon and multiplying reported propane use by .0915 to arrive at each new customer's anticipated Dth use. Historical data indicates that the relationship between design day and annual load is such that design day usage is approximately 1% of annual usage;[2] and, as a result, design day requirement forecasting for the new customers was based on 1% of the anticipate Dth factored from the reported propane usage.

GMG anticipates the bulk of its substantial growth in two wholly new locations, identified in its supporting information as Project 1 and Project 2. The vast majority of the new customers in both projects are primarily commercial; and, most of the new customers are firm customers.[3] GMG's calculations supporting the anticipated design day impact from its two new projects are set forth in Attachment A. As a result of that calculation, GMG anticipates that there will be an increase of 3,059 Dth to its design day demand in 2013-2014. Factoring in for a five percent reserve margin of 153 Dth, GMG attributes 3,212 Dth of its increased contract demand entitlement requirements to the growth it is experiencing from commercial customers in Project 1 and Project 2.

b. Statistical Analysis of GMG's Existing Customer Historical Data Suitably Forecasts Likely Design Day Requirements for 2013-2014.

With respect to its existing customers, GMG employed an ordinary least square regression analysis methodology to predict peak day demand. 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 2013-2014 heating season is based on 5,858 Dth, which is an increase of 649 Dth over the 2012-2013 design day requirements. The derivation of the design day forecast can be seen in Attachment B, Page 2 of 3.

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2 . GMG's historical data demonstrates that the average Dth allocated to design day requirements is approximately 1% of the annual load after considering usage data, the number of heating degree days in the year, and adjustments for base load.

3 . For customers where usage is seasonal and is expected to be non-existent or negligible during the heating season, as well as new customers that will not begin using gas until the spring of 2014, GMG identified "0" anticipated Dth use in its data, as those customers do not require peak day gas supply for the 2013-2014 heating season.

Attachment B 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 2010 through March 2013. The firm sales volume data was correlated to geographic weather data by assigning town border station locations geographically to weather sites as follows:

Weather Site	TBS Location
Mankato	Rapidan
Mankato	Madison inks
Faribault	Heidelberg
Faribault	Forest
Faribault	Faribault 5
Shakopee	Marystown

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 2013-2014 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:

$$Y = a + b X$$

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:

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

The combination of accepted statistical modeling methodology to obtain quantitative data for forecasting purposes, along with qualitative information supplied by GMG's new customers, 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.

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. The summary is based on usage for the twelve month period ending June 30, 2013.

Seasonal Customer Usage By Class (Dth)			
	Winter	Summer	Total
Residential - Firm	289,659	120,366	410,026
Commercial - Firm	14,804	11,064	25,868
Industrial - Firm	25,759	13,447	39,206
Flexible Rate - Firm	17,377	6,285	23,661
Total Firm	*347,599*	*151,162*	*498,761*
Agricultural - Interruptible	*1,132*	*13,863*	*14,995*
Industrial - Interruptible	4,443	1,450	5,894
Flexible Rate - Interruptible	3,050	29,986	33,035
Total Interruptible (Non-Ag)	*7,493*	*31,436*	*38,929*
Total	**356,224**	**196,461**	**552,685**

GMG's proposed increase in its contract demand entitlement will assure sufficient supply and reliability for its customers throughout the heating season. In considering its contract changes, GMG also secured additional supply for the summer months to serve its increased customer base. In the event that its customers' summer demands would exceed it contract supply, GMG intends to purchase capacity release gas during the summer months which can be acquired very inexpensively. It is more cost-effect for the rate-payers to utilize capacity release gas during the summer months than to contract for additional supply that may not be needed because of over-estimated usage. 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, 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 C. In addition to the contract supply sources summarized in Attachments C and D, the attachments also identify that GMG has contracted for 950 Dth per day of gas delivered to the Town Border Station available for peak day capacity; and, since that contract is for delivered gas, its cost is included in GMG’s commodity rates and it does not carry an associated demand charge. GMG is served by the Northern Natural Gas pipeline system. Attachment D identifies the contracts GMG holds with Northern Natural Gas, specifically noting proposed changes to those contracts for the 2013-2014 heating season and the corresponding change in contract demand costs.

Project 2 is located in a geographical area lying markedly north of GMG’s historical service territory. Consequently, GMG has secured an independent supply of gas to support Project 2.[4] GMG plans to backhaul gas from the Viking[5] line at North Branch. However, in the unlikely event that backhauled gas is not available, supply needs for Project 2 will be met with acquisition of gas at Emerson that will be forward-hauled to an alternate receipt point. Hence, GMG’s Project 2 customers can be served under any condition with sufficient physical reliability. Moreover, to the extent that planned supply allocated to Project 2 is not fully utilized by that project, the gas can be delivered to an alternate point and can be used elsewhere in GMG’s integrated system. In addition to additional capacity on the Northern Natural Gas system, this allows GMG 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. Despite the fact that GMG’s proposed contract demand entitled is substantially larger than the previous year’s, GMG’s customers should not suffer increased demand rates. As shown, the rate impact is actually anticipated to be a slight reduction in customer rates, as GMG projects that the combination of additional incremental sales to the new customers along with its

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[4]. The independent gas supply anticipated to support Project 2 can also be rerouted as necessary and become part of GMG’s aggregate gas supply, thus creating an integrated supply system.

[5]. The Viking Gas Transmission Company provides transport services only, being connected to major pipeline systems, allowing for strategic transport of delivered gas.

supply changes will more than offset the cost of the increased demand. Therefore, there is no adverse impact to customer rates as a result of the increased demand entitlement, which further supports its approval.

REQUEST FOR COMMISSION ACTION

GMG is confident that its proposed increase in its contract demand entitlement is both necessary and soundly planned. As the supporting information demonstrates, GMG engaged in sufficient coordination between its gas-supply planning for the 2013-1024 heating season and its broader corporate planning. GMG's various assumptions and methodologies for its design day analysis are well documented and appropriate. Most importantly, 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 2013-2014 Heating Season.

Dated: August 15, 2013

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
Anticipated Design Day Impact From Commercial Customers In Projects 1 and 2

Trade Secret Data Begins

Project 1 Anticipated Load		
Customer	Reported Propane Use (gallons)	Anticipated Dth Requirements
Redacted Trade Secret Data *Table Contains Proprietary Customer Information*		
Total	*821,585*	*64,195*
Design Day Impact = 1% of Annual Load = 642 Dth		

Trade Secret Data Ends

Trade Secret Data Begins

Project 2 Anticipated Load		
Customer	Reported Propane Use (gallons)	Anticipated Dth Requirements
Redacted Trade Secret Data *Table Contains Proprietary Customer Information*		
Total	*2,741,621*	*241,703*
Design Day Impact = 1% of Annual Load = 2,417 Dth		

Trade Secret Data Ends

ATTACHMENT B
Design Day Regression Analysis Background Information

Greater Minnesota Gas, Inc.
Contract Demand Entitlement Filing 2013 - 2014 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)]
2013-2014 Est (1/31)	5,204	430	9.01%	5,858	894	18.01%	9,359	4,150	79.67%	59.76%
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)
2012-2014	Unknown			0.673	1.1257	1.7984	Unknown
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 4/
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 2013 - 2014
Derivation of Design Day Use Per Customer

Linear Regression Analysis Period: November thru March 2010-2013

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	-36.18	17.63	90	1,551	0.9201	Y Inter + Slope x Design HDD = Estimated Design Dth
2	Forest, Heidelberg, and Faribault 5	Faribault	-69.86	32.73	90	2,876	0.8688	
3	Marystown	Shakopee	14.45	6.34	90	585	0.9158	
			-91.59	56.70				
4				**Total Design Dths**		**5,012**		
5				**Estimated Interruptible Load**		**40**		
6				**Net Design Dths**		**4,972**		Line 4 - Line 5
7				**Average Customer Count (12/2011 & 12/2012)**		**4,417**		
8				**Design Dths/Customer**		**1.1257**		Line 6 / Line 7
9				**Estimated Firm Customers for 2013/2014**		**5,204**	*	
10				**Design Dths 2013/2014**		**5,858**		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 2012-13	Peak Day 2011-12	Peak Day 2010-11
1	Date of Peak Day		31-Jan-13	19-Jan-12	21-Jan-11
2	Day of the Week		Thursday	Thursday	Friday
3	Total Throughput (Dth)	5898	5038	3710	3905
4	Interruptible Customer Usage (Dth)	40	13	53	40
5	Firm Transportation Usage (Dth)	0	150	132	8
6	Firm Sales Throughput (Dth)	5858	4875	3525	3857
7	Average Actual Gas Day Temperature (Deg. F)	-25	-1	-3	-10
8	Heating Degree Days (HDD) 65 degree base	90	66	68	75
9	Non-HDD Sensitive Base (Dth)	-92	-92	301	363
10	Total HDD Sensitive Firm Throughput (Dth)	5950	4967	3224	3494
11	Actual Firm Peak Day Dth/HDD (Dth)	66	75	47	47
12	Base + (Actual Dth/HDD * HDDs) (Dth)	5858	4875	3525	3857
13	Peak Month Firm Customers	5204	4774	4216	3897
14	Peak Day Use per Firm Customer	1.126	1.021	0.836	0.990
			Sales Jan '13	% of Total	
15	Firm Sales				
16	Residential		70,602	77.0%	
17	Commercial		9,659	10.5%	
18	Industrial		6,684	7.3%	
19	Flexible Rate Industrial		4,802	5.2%	
20	Total Firm Sales		91,747	100.0%	
21	Allocated Peak Day based on Dth Sales				
22	Residential	4,508	3,751	77.0%	
23	Commercial	617	513	10.5%	
24	Industrial	427	355	7.3%	
25	Flexible Rate Industrial	307	255	5.2%	
26	Total Firm Sales	5,858	4,875	100%	

ATTACHMENT C
Demand Profile and Supply Comparison

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

2011 - 2012 Heating Season	Quantity (Dth)	2012 - 2013 Heating Season	Quantity (Dth)		2013 - 2014 Heating Season	Quantity (Dth)	Change in Quantity (Dth)
TF-7 (Summer - Apr. - Oct.)	**300**	**TF-7 (Summer - Apr. - Oct.)**	**300**		**TF-7 (Summer - Apr. - Oct.)**	**-**	**(300)**
TF 12 (Nov. - Oct.)	**210**	**TF 12 (Nov. - Oct.)**	**210**		**TF 12 (Nov. - Oct.)**	**630**	**420**
TFX-7 (Oct. - Apr.))	**500**	**TFX-7 (Oct. - Apr.))**	**665**		**TFX-7 (Oct. - Apr.))**	**665**	**-**
TFX-5 (Nov. - Mar.)	**4,244**	**TFX-5 (Nov. - Mar.)**	**4,244**		**TFX-5 (Nov. - Mar.)**	**6,844**	**2,600**
Viking Zone 1		**Viking Zone 1**		**(2)**	**Viking Zone 1**	**2,000**	**2,000**
TFX-5 (Nov. - Mar.)	**90**	**TFX-5 (Nov. - Mar.)**	**90**		**TFX-5 (Nov. - Mar.)**	**270**	**180**
Delivery Contract		**Delivery Contract**		**(3)**	**Delivery Contract**	**950**	**950**
Capacity Release - Non-recallable	**-**	**Capacity Release - Non-recallable**	**-**		**Capacity Release - Non-recallable**	**-**	**-**
SMS	1,300	SMS	1,300		SMS	1,300	**-**
Heating Season Total Capacity	5,044	Heating Season Total Capacity	5,209		Heating Season Total Capacity	9,359	4,150
Non-Heating Season Total Capacity	510	Non-Heating Season Total Capacity	510		Non-Heating Season Total Capacity	630	120
Total Entitlement @ Peak	5,044	Total Entitlement @ Peak	5,209		Total Entitlement @ Peak	9,359	4,150
Total Annual Transportation	-	Total Annual Transportation	-		Total Annual Transportation	-	-
Total Season Transportation	5,044	Total Season Transportation	5,209		Total Season Transportation	9,359	4,150
Total Percent Summer Vs. Winter	10.1%	Total Percent Summer Vs. Winter	9.8%		Total Percent Summer Vs. Winter	6.7%	
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/ Company has contract for supply delivered to TBS. No demand charges are applicable, but the 950 dekatherms is available on peak day.

ATTACHMENT D
Contract Entitlement Changes

Greater Minnesota Gas, Inc.
Northern Natural Gas Contract Summary
Contract Entitlement Changes as of November 1, 2013

Contract Entitlements 2012-13

	Contract No.	Service Type	Rate Schedule	Months		Entitlement (Dth)		Expiration Date
	110439	Syst Mgmt Serv	SMS	Apr-Oct		50	/1	10/31/2013
	110439	Firm Throughput	TFX - 7	Apr-Oct		300	/1	10/31/2013
	102985	Syst Mgmt Serv	SMS	Nov-Mar		1,300		10/31/2017
	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		3/31/2014
	102985	Firm Throughput	TF - 12	Nov-Mar		244		3/31/2015
	121534	Firm Throughput	TFX - 7	Oct-Apr		665		10/31/2015
	120579	Firm Throughput	TF - 12	Oct-Sep		210		9/30/2017
	120579	Firm Throughput	TF - 5	Nov-Mar		90		9/30/2017
			2012-13 Heating Season Total Capacity			5,209		
			2012-13 Design Day Demand			5,858		
			Reserve Margin			(649)		-11.1%

Proposed Contract Entitlement Changes for 2013-14

Start Date	Contract No.	Service Type	Rate Schedule	Months		Entitlement (Dth)		Expiration Date
11/1/2013	102985	Firm Throughput	TFX - 5	Nov-Mar	*	2,100		3/31/2014
11/1/2013	102985	Firm Throughput	TFX - 5	Nov-Mar	*	500	/2	
11/1/2013	120579	Firm Throughput	TF-5	Nov-Mar	*	180	/2	
11/1/2013	120579	Firm Throughput	TF-12	Nov-Sep	*	420	/2	
11/1/2013		Contracted Delivery		Nov-Sep		950	/3	4/30/2015
			2013-14 Heating Season Total Capacity			9,359		
			2013-14 Design Day Demand			8,917		
			Reserve Margin			442		5.0%

Proposed Change in Contract Demand Costs

Contract No.	Rate Schedule	Volume Dth / Day	No. of Months		Monthly Demand Rates	Total Annual Cost
Viking	Zone 1	2,000	12		$ 3.4671	$ 83,210.40
102985	TFX - 5	2,100	5	/4	$ 15.1530	$ 159,106.50
102985	TFX - 5	500	5	/4	$ 15.1530	$ 37,882.50
120579	TF-5	180	5	/4	$ 15.1530	$ 13,637.70
120579	TF-12	420	5	/4	$ 10.2300	$ 21,483.00
120579	TF-12	420	7	/4	$ 5.6830	$ 16,708.02
						$ 332,028.12

/1 This contract was not renewed
/2 This amount to be added to the contracts.
/3 Contracted amount through supply.
/4 Increase to previously approved entitlements.

* Contract has Right of First Refusal on Extension

ATTACHMENT E
Rate Impact of Proposed Contract Demand Entitlement

Greater Minnesota Gas, Inc.
Contract Demand Entitlement Filing
Rate Impact - November 2013

	Annualized Impact									
Residential	Last Rate Case 1/	Last Demand Change 2/	Current PGA w/o Demand Ent. Change (Nov. 1, 2012)	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	$ 3.8768	$ 3.8768	$ 3.8768	$ (2.0033)	-34.07%	$ -	0.00%	$ -	0.00%
Demand Cost of Gas	$ 0.8293	$ 1.0044	$ 1.0044	$ 0.9178	$ 0.0885	10.67%	$ (0.0866)	-8.62%	$ (0.0866)	-8.62%
Total Cost of Gas	$ 6.7094	$ 4.8812	$ 4.8812	$ 4.7946	$ (1.9149)	-28.54%	$ (0.0866)	-1.77%	$ (0.0866)	-1.77%
Average Annual Usage (Dth)	87.1	87.1	87.1	87.1						
Average Annual Total Cost of Gas	$ 584.21	$ 425.02	$ 425.02	$ 417.48	$ (166.73)	-28.54%	$ (7.54)	-1.77%	$ (7.54)	-1.77%

	Annualized Impact									
Commercial & Industrial Firm	Last Rate Case 1/	Last Demand Change 2/	Current PGA w/o Demand Ent. Change (Nov. 1, 2012)	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	$ 3.8768	$ 3.8768	$ 3.8768	$ (2.0033)	-34.07%	$ -	0.00%	$ -	0.00%
Demand Cost of Gas	$ 0.8293	$ 1.0044	$ 1.0044	$ 0.9178	$ 0.0885	10.67%	$ (0.0866)	-8.62%	$ (0.0866)	-8.62%
Total Cost of Gas	$ 6.7094	$ 4.8812	$ 4.8812	$ 4.7946	$ (1.9149)	-28.54%	$ (0.0866)	-1.77%	$ (0.0866)	-1.77%
Average Annual Usage (Dth)	1,365.2	1,365.2	1,365.2	1,365.2						
Average Annual Total Cost of Gas	$ 9,159.43	$ 6,663.58	$ 6,663.58	$ 6,545.35	$ (2,614.0823)	-28.54%	$ (118.23)	-1.77%	$ (118.23)	-1.77%

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 **November 1, 2012**

Reason for change: Change in cost of gas due to an estimated increase in the market price of natural gas from October 2012.

This PGA is based on the following Northern Natural Gas Tariffs:
- 4th Revised Sheet No. 50
  - Issued: 2/1/12
  - Effective: 4/1/12
- 4th Revised Sheet No. 51
  - Issued: 2/1/12
  - Effective: 4/1/12
- Original Sheet No. 55
  - Issued: 9/24/10
  - Effective: 9/24/10

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**

II. Greater Minnesota Gas, Inc. Rates - Current Cost of Gas Effective **November 1, 2012**

Commodity Cost of Gas: $0.387680 WACOG

III. 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

IV. Greater Minnesota Gas, Inc.'s -- Current Cost of Gas Effective **November 1, 2012**

All Customer Sales Rate Classes	MCF	x Months	x Tariff Rate		Equals	Rate/CCF Firm	Rate/CCF Ag Interr	Rate/CCF Gen Interr
TFX - 7	300	7	$5.6830		11,934	$0.002773		
TFX - 5	4,244	5	$15.1530		321,547	$0.074711		
TF - 12	210	5	$10.2300		10,742	$0.002496		
TF - 12	210	7	$5.6830		8,354	$0.001941		
TF - 5	90	5	$15.1530		6,819	$0.001584		
TFX - 7	665	5	$15.1530		50,384	$0.011707		
TFX - 7	665	2	$5.6830		7,558	$0.001756		
SMS Demand	50	7	$2.1800		763	$0.000177		
	1,300	5	$2.1800		14,170	$0.003292		
Current Demand Cost of Gas					$432,270	**$0.100437**	**$0.000000**	**$0.000000**
Current Commodity Cost of Gas/CCF			% of Total	81%	**$1,851,424**	**$0.387680**	**$0.387680**	**$0.387680**
Total Cost of Gas/CCF					**$2,283,694**	**$0.488117**	**$0.387680**	**$0.387680**

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	$0.014168	($0.256773)	$0.004070	**($0.238535)**	$0.000000	($0.256773)	$0.224950	**($0.031823)**	$0.000000	($0.256773)	($0.031450)	**($0.288223)**
3) Current Adj	$0.003340	$0.056440	$0.000000	**$0.059780**	$0.000000	$0.056440	$0.000000	**$0.056440**	$0.000000	$0.056440	$0.000000	**$0.056440**
4) PGA Billed (2+3)	$0.017508	($0.200333)	$0.004070	**($0.178755)**	$0.000000	($0.200333)	$0.224950	**$0.024617**	$0.000000	($0.200333)	($0.031450)	**($0.231783)**
5) Average Cost of Gas	$0.100437	$0.387680	$0.004070	**$0.492187**	$0.000000	$0.387680	$0.224950	**$0.612630**	$0.000000	$0.387680	($0.031450)	**$0.356230**

	Prior Cumulative Adjustments	Demand & Commodity Change Filed Herein	True-up Adjustment Factor Change Eff. September 1, 2012 (G022/AA-12-___)	Current PGA Adjustment
All Firm Sales Rate Classes (/CCF)	($0.242605)	$0.059780	$0.004070	**($0.178755)**
Ag Inter. Sales Rate Classes (/CCF)	($0.256773)	$0.056440	$0.224950	**$0.024617**
Gen. Inter. Sales Rate Classes (/CCF)	($0.256773)	$0.056440	($0.031450)	**($0.231783)**

		1	2	3	4	5	7
November 1, 2012	Tariff Rate Designation	Non-gas Commodity Margin	Commodity Cost ($/CCF)	Demand Other PGA Expenses	Total Cost of Gas ($/CCF)	True-up Factor ($/CCF)	Total Billing Rate
Rate Class		($/CCF)		($/CCF)	(2)+(3)+(4)		($/CCF)
Residential	RS1	$0.444330	$0.387680	$0.100437	$0.488117	$0.004070	$0.936517
Small Commercial CS1	SCS1	$0.426330	$0.387680	$0.100437	$0.488117	$0.004070	$0.918517
Commercial CS1	CS1	$0.396330	$0.387680	$0.100437	$0.488117	$0.004070	$0.888517
Commercial/Industrial MS1	MS1	$0.376330	$0.387680	$0.100437	$0.488117	$0.004070	$0.868517
Commercial/Industrial LS1	LS1	$0.361330	$0.387680	$0.100437	$0.488117	$0.004070	$0.853517
Agricultural - Interruptible	AG1	$0.231310	$0.387680	$0.000000	$0.387680	$0.224950	$0.843940
General Interruptible	IND1	$0.251310	$0.387680	$0.000000	$0.387680	-$0.031450	$0.607540
General Interruptible - Flex	IND1 - FL	$0.030000	$0.387680	$0.000000	$0.387680	-$0.031450	$0.386230

Estimated Gas Volumes -November, **2012** 449,990 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, 2013** **Illustrative Only**

Reason for change: Change in cost of gas due to an estimated Decrease in the market price of natural gas from October 2013.

This PGA is based on the following Northern Natural Gas Tariffs:
5th Revised Sheet No. 50
Issued: 2/1/13
Effective: 4/1/13
5th Revised Sheet No. 51
Issued: 2/1/13
Effective: 4/1/13
Original Sheet No. 55
Issued: 9/24/10
Effective: 9/24/10

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, 2013 Illustrative**

Commodity Cost of Gas	$0.385610	WACOG

III. Annual Sales Volume - 2013-2014 Budget (September - August) **9,064,590**

Sales Service Volume - CCF	**8,197,780**
Interruptible Service Volume - CCF	**866,810**

IV. Greater Minnesota Gas, Inc.'s -- Current Cost of Gas Effective **November 1, 2013 Illustrative**

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	$3.4671		83,210	$0.010150		
	TFX - 5	6,844	5	$15.1530		518,536	$0.063253		
	TF - 12	630	5	$10.2300		32,225	$0.003931		
	TF - 12	630	7	$5.6830		25,062	$0.003057		
	TF - 5	270	5	$15.1530		20,457	$0.002495		
	TFX - 7	665	5	$15.1530		50,384	$0.006146		
	TFX - 7	665	2	$5.6830		7,558	$0.000922		
	SMS Demand	50	7	$2.1800		763	$0.000093		
		1,300	5	$2.1800		14,170	$0.001729		
	Current Demand Cost of Gas					$752,364	**$0.091777**	**$0.000000**	**$0.000000**
	Current Commodity Cost of Gas/CCF			% of Total	82%	**$3,495,397**	**$0.385610**	**$0.385610**	**$0.385610**
	Total Cost of Gas/CCF					**$4,247,761**	**$0.477387**	**$0.385610**	**$0.385610**

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	$0.017508	($0.167523)	($0.004520)	**($0.154535)**	$0.000000	($0.167523)	$0.065020	**($0.102503)**	$0.000000	($0.167523)	($0.019530)	**($0.187053)**
3) Current Adj	($0.008661)	($0.034880)	$0.000000	**($0.043541)**	$0.000000	($0.034880)	$0.000000	**($0.034880)**	$0.000000	($0.034880)	$0.000000	**($0.034880)**
4) PGA Billed (2+3)	$0.008848	($0.202403)	($0.004520)	**($0.198075)**	$0.000000	($0.202403)	$0.065020	**($0.137383)**	$0.000000	($0.202403)	($0.019530)	**($0.221933)**
5) Average Cost of Gas	$0.091777	$0.385610	($0.004520)	**$0.472867**	$0.000000	$0.385610	$0.065020	**$0.450630**	$0.000000	$0.385610	($0.019530)	**$0.366080**

	Prior Cumulative Adjustments	Demand & Commodity Change Filed Herein	True-up Adjustment Factor Change Eff. September 1, 2012 (G022/AA-12-___)	Current PGA Adjustment
All Firm Sales Rate Classes (/CCF)	($0.150015)	($0.043541)	($0.004520)	**($0.198075)**
Ag Inter. Sales Rate Classes (/CCF)	($0.167523)	($0.034880)	$0.065020	**($0.137383)**
Gen. Inter. Sales Rate Classes (/CCF)	($0.167523)	($0.034880)	($0.019530)	**($0.221933)**

		1	2	3	4	5	7
November 1, 2013	Tariff Rate Designation	Non-gas Commodity Margin	Commodity Cost ($/CCF)	Demand Other PGA Expenses	Total Cost of Gas ($/CCF)	True-up Factor ($/CCF)	Total Billing Rate
Rate Class		($/CCF)		($/CCF)	(2)+(3)+(4)		($/CCF)
Residential	RS1	$0.444330	$0.385610	$0.091777	$0.477387	-$0.004520	$0.917197
Small Commercial CS1	SCS1	$0.426330	$0.385610	$0.091777	$0.477387	-$0.004520	$0.899197
Commercial CS1	CS1	$0.396330	$0.385610	$0.091777	$0.477387	-$0.004520	$0.869197
Commercial/Industrial MS1	MS1	$0.376330	$0.385610	$0.091777	$0.477387	-$0.004520	$0.849197
Commercial/Industrial LS1	LS1	$0.361330	$0.385610	$0.091777	$0.477387	-$0.004520	$0.834197
Agricultural - Interruptible	AG1	$0.231310	$0.385610	$0.000000	$0.385610	$0.065020	$0.681940
General Interruptible	IND1	$0.251310	$0.385610	$0.000000	$0.385610	-$0.019530	$0.617390
General Interruptible - Flex	IND1 - FL	$0.030000	$0.385610	$0.000000	$0.385610	-$0.019530	$0.396080

Estimated Gas Volumes -November, 2013 995,280 Ccf

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 2013-2014 Heating Season

Docket No. ________________

filed this 19^{h} day of August, 2013.

/s/ Kristine A. Anderson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St. St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Bob	Emmers	bemmers@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 St. Paul, MN 551012198	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St. St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.	202 S. Main Street P.O. Box 68 Le Sueur, MN 56058	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Greater Minnesota Gas, Inc._Official Service List