GREAT PLAINS
NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

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July 2, 2012

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: Demand Entitlement Filing
Docket No. G004/M-12-___

Dear Dr. Haar:

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith electronically submits its Demand Entitlement Filing pursuant to Minnesota Rule 7825.2910, Subpart 2 for the 2012-2013 winter heating season.

Great Plains is requesting to change its demand portfolio to reflect changes in the North District gas supply and transportation contracts resulting from the expiration of the current contracts. Such changes will also result in a slight increase in capacity available to serve North District customers. South District capacity will remain unchanged. Great Plains requests that changes in the capacity be effective November 1, 2012, which corresponds with the effective date of new transportation contract in the North District and with Northern Natural Gas Co.'s (Northern) TF12 Base and Variable capacity reallocation.[1]

In support of the filing Great Plains has attached the following exhibits:

Exhibit A – Demand Profile
Exhibit B - Transportation contract cost analysis
Exhibit C – Design Day Capacity
Exhibit D – Rate Impacts
Exhibit E – Demand Entitlement Analysis

[1] Great Plains is submitting its filing at this time in light of (1) the Department's recommendation in its February 2, 2012 Comments in Docket No. G004/M-11-1075 that Great Plains file its annual demand entitlement filings by July 1 each year going forward; and (2) the significant changes in the North District gas supply and transportation contracts that will be effective November 1, 2012.

Exhibit A - Demand Profile

In the North District, Great Plains has entered into new upstream gas supply and transportation contracts to replace Great Plains' long term transportation and supply contract with ProGas, which expires on October 31, 2012. As described below and in Exhibit B, Great Plains' customers will benefit considerably from this change.

The new contracts will provide firm transportation capacity on Northern and supply from the Ventura, Iowa interconnect point between Northern Border Pipeline (Northern Border) and Northern. While the existing contract with ProGas proved to be a reliable source of natural gas, with the loss of demand for pipeline capacity on the TransCanada Pipeline (TransCanada) system, the demand charges have increased to a point that is cost-prohibitive to continue serving the North District customers via this pipeline.

Under Great Plains' replacement contracts, North District customers will continue to receive natural gas through Viking Gas Transmission Company (Viking), however, the source of the natural gas will switch from the Emerson receipt point on TransCanada Pipeline to Northern's pipeline at the interconnect between Northern and Viking. Effective November 1, 2012, the firm transportation services upstream of Viking will originate on Northern's pipeline system at the interconnect with Northern Border at Ventura, Iowa. The North District supply of natural gas will enter Viking's system at the receipt point between Northern and Viking known as the Chisago interconnect. Please see pages 4-5 of Exhibit A for a map illustrating the changes in the interconnection points. By accessing natural gas from Northern Border, Great Plains will have access to numerous marketers with which Great Plains has established working relationships. The Northern Border-Ventura point is a liquid point with active trading.

The new Northern contract has a term of 11.5 years and will supply 13,000 dk per day of capacity to the North District customers. In addition to the 13,000 dk per day, Great Plains will continue to utilize the 2,000 dk per day on Northern that, in the past, has been used to meet the peak day demand of its firm sales customers. The total supply allocated to the North District will be 15,000 dk per day, a modest increase of 159 dk from the 2011-2012 winter levels.

In conjunction with the new Northern contracts, Great Plains will retain 5,000 dk per day of forward haul on the Viking system. In addition to the 5,000 dk of forward haul capacity, 8,000 dk per day of new firm back haul capacity will be contracted to meet the peak day requirement. This will be in addition to the current seasonal firm back haul capacity of 2,000 dk per day which Great Plains has contracted for and utilized for many years. This will result in a total of 10,000 dk per day of firm back haul capacity during the heating season, thus meeting the 15,000 dk per day of supply noted above.

In the South District, pursuant to Northern's FERC tariff, Northern adjusts each TF12 contract between TF12 Base and TF12 Variable effective November 1 of each year, based on the amount of capacity used during the preceding May – September period. At this time, the amount of the adjustment is not yet known, however the change is normally not significant and there is no deliverability difference between the TF12 Base and TF12 Variable entitlement. The change in the TF12 Base and TF12 Variable will be known by November 1, 2012. The changes to pipeline contracts will also affect the South District, as summer capacity agreements on the TransCanada/Viking system will no longer be used, which will reduce demand charges to customers by approximately $0.30 per dk, or 20.4 percent from the June 2012 PGA.

These changes in capacity are supported by Great Plains' design day studies and demand entitlement analysis in Exhibit C. Great Plains' analyses indicate that it will have adequate capacity to serve its firm service customers in the 2012-2013 heating season.

Finally, pages 2 and 3 of Exhibit A show the demand profile history for the 2010-2011, 2011-2012 and proposed 2012-2013 heating seasons.

<u>Exhibit B – Transportation Contract Analysis</u>

With the imminent expiration of the ProGas gas supply and pipeline transportation contract in October 2012, Great Plains began to review potential options for the replacement of the contract beginning in 2008-2009. Great Plains reviewed options available to serve the North District customers with the goal of providing the most reliable and economic firm transportation service to meet the current and future demand. Great Plains considered four different scenarios ranging from a continuation of the existing contract with ProGas to directly contracting with Northern and using Viking back haul capacity.

After reviewing the options, it was determined that a contract with Northern was the most reliable and economic manner to serve customers. Exhibit B provides Great Plains' cost analysis supporting the determination that entering into the contracts with Northern better serves the long-term interests of Great Plains' customers.

In particular, Great Plains determined that contract for firm transportation service similar to the existing ProGas contract would continue to expose customers to the high demand charges on the upstream TransCanada pipeline. With the continued decontracting on the TransCanada system, the demand charges are expected to, at a minimum, stay at the current high rate or continue to escalate in the future as other shippers are expected to leave that system due to the high demand charges. The current demand charge level in the North District has been of concern as the rates to customers have increased approximately 55 percent since November 2008, primarily due to changes in TransCanada pipeline rate increases. The current high transportation charges, along with potentially higher charges in the future were the primary factor in ruling out the option to continue to use TransCanada/Viking as the means of providing service to customers once the current contract expires. In addition to the cost savings, Northern is a reputable pipeline and is well positioned to take advantage of transporting the escalating supply of shale gas in the mid-continent and southern United States to meet customer needs at a competitive price.

Great Plains also notes that while reviewing the gas supply options for the North District, Great Plains attempted to contract for storage capacity on Northern's system as part of the supply portfolio. The supply of storage would have provided customers with a physical hedge and a level of price stability during the heating season. The proposal submitted by Great Plains was rejected by Northern as other offers were of longer term and accepted by Northern.

Exhibit C – Design Day Capacity

In support of its proposed demand profile, Great Plains has provided its design day calculations for the North District and South District in Exhibit C.

On June 27, 2012, Great Plains filed its Compliance filing pursuant to the Commission's Order in Docket Nos. G004/M-07-1401, G004/M-08-1306, G004/M-9-1262, and G004/M-10-1164. In its Order, the Commission required Great Plains to develop a design day forecast methodology that addressed the concerns of the Department that were raised in the referenced dockets. Great Plains worked with the Department to review its design day methodology and potentially develop a new design day forecast methodology. Great Plains and the Department ultimately concluded that Great Plains' current design day methodology did not produce unreasonable results and Great Plains should continue to use its methodology for determining design day demand.[2]
In compliance with Docket No. G004/M-03-303 and its Agreement with the Department, Great Plains performed a regression analysis using 36 months of history in its design day methodology. This produces an estimate of the design day demand for firm gas service and supports the required pipeline capacity levels. Due to the different weather patterns in its service area, Great Plains performed regressions for the South District, Crookston and Fergus Falls areas in the North District, and Wahpeton, North Dakota. Based on the study and Great Plains' proposed capacity levels, Great Plains is anticipating a reserve margin of 5.3 percent in the North District and 5.4 percent in the South District. This level of reserve margin is consistent with the Commission's directive in its September 30, 2010 Order in Docket No. G004/M-09-1262 that Great Plains reduce its reserve margin to approximately 5 percent in the North District and South District. Great Plains' proposed reserve levels comply with the Commission's directive.

Future Changes

The current abundance of supply, with the economic energy source natural gas provides, is bringing about the conversion of users of alternate fuels to natural gas as the desired form of energy. Great Plains has seen a renewed interest for natural gas

[2] As noted in Great Plains' June 27 Compliance Filing, Great Plains agreed to include in its demand entitlement filing a discussion and supporting calculations, comparing actual usage for new construction to usage for older construction on both its North and South Districts. Great Plains is in the process of preparing this analysis and intends to supplement the current filing when the analysis is complete.

throughout its service territory and the decrease in demand charges for the North District customers could result in additional requests for natural gas. Great Plains will continue to monitor customer growth and related increase in demand as well as the offsetting effect of conservation.

Exhibit D – Rate Impacts

Exhibit D shows the impacts to customers due to the capacity changes discussed above. The result of the changes in the contract is a decrease in the demand rate components for North District firm customers of 60.8 percent and a decrease of 20.4 percent for South District firm customers from the rates in effect in June 2012.

Exhibit E – Demand Entitlement Analysis

Exhibit E reflects the historical design day requirement, total entitlement and peak day design, entitlement and firm sendout per customer for the 1995-1996 to the 2012-2013 heating seasons.

If you have any questions regarding this filing, please contact me at (701) 222-7854, or Brian M. Meloy, at (612) 335-1451.

Sincerely,

/s/ *Rita A. Mulkern*

Rita A. Mulkern
Regulatory Affairs Manager

cc: Brian M. Meloy

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2011 - 2012 HEATING SEASON
DEMAND PROFILE EFFECTIVE NOVEMBER 1, 2012

Type of Capacity or Entitlement	Current Amount	Proposed Change	Proposed Amount	Contract Length	Expiration Date
Demand Profile for South District (dk):					
TF12 Base (Summer & Winter) 1/	5,644	0	5,644	5 years	10/31/14
TF12 Variable (Summer & Winter) 1/	1,891	0	1,891	5 years	10/31/14
TF5 (November - March) 1/	3,410	0	3,410	5 years	10/31/14
TFX Seasonal (November - March)	4,700	0	4,700	5 years	10/31/14
Subtotal	15,645	0	15,645		
FT-A - Zone 1-1 (April - October)	500	0	500	1 Year	10/31/13
FT-A - Zone 1-2 (April - October)	4,500	0	4,500	1 Year	10/31/13
SMS	2,500	0	2,500	5 Years	10/31/14
FDD-1 Reservation	4,640	0	4,640	5 Years	5/31/16
LP Peak-Shaving	0	0	0		
Heating Season Total Capacity:	15,645	0	15,645		
Non-Heating Season Total Capacity:	7,535	0	7,535		
Forecasted Heating Season Design Day:	14,868	(18)	14,850		
Estimated Non-Heating Season Design Day:	10,065	(2,186)	7,879		
Heating Season Capacity: Surplus/(Shortage)	777	18	795		
Non-Heating Season Capacity: Surplus/(Shortage)	(2,530)	2,186	(344)		
Demand Profile for North District (dk) 2/					
FT-A	7,841	(7,841)	0	5 Years	10/31/12
FT-A (Backhaul)	0	8,000	8,000	5 Years	10/31/17
FT-A - Zone 1-1 (November - March)	500	0	500	1 Year	10/31/13
FT-A - Zone 1-2 (November - March)	4,500	0	4,500	1 Year	10/31/13
TFX Seasonal (November - March)	2,000	0	2,000	20 Years	10/31/14
Subtotal	14,841	159	15,000		
FT-A Seasonal (November - March) 3/	2,000	0	2,000	2 Years	10/31/13
LMS Demand	2,500	0	2,500	1 Year	10/31/13
Brokered Reservation Charge (Emerson):	13,015	(13,015)	0	15 Years	10/31/12
TFX (Annual)	0		13,000	11.5 Years	3/31/24
Heating Season Total Capacity:	14,841	159	15,000		
Non-Heating Season Total Capacity:	7,841	159	8,000		
Forecasted Heating Season Design Day:	14,068	27	14,095		
Estimated Non-Heating Season Design Day:	10,315	(2,136)	8,179		
Heating Season Capacity: Surplus/(Shortage)	773	132	905		
Non-Heating Season Capacity: Surplus/(Shortage)	(2,474)	2,295	(179)		

1/ Effective November 1, 2011.
2/ Minnesota North District communities plus Wahpeton, ND.
3/ Northern Natural North Branch Backhaul.

GREAT PLAINS NATURAL GAS CO.
DEMAND PROFILE
NORTH DISTRICT

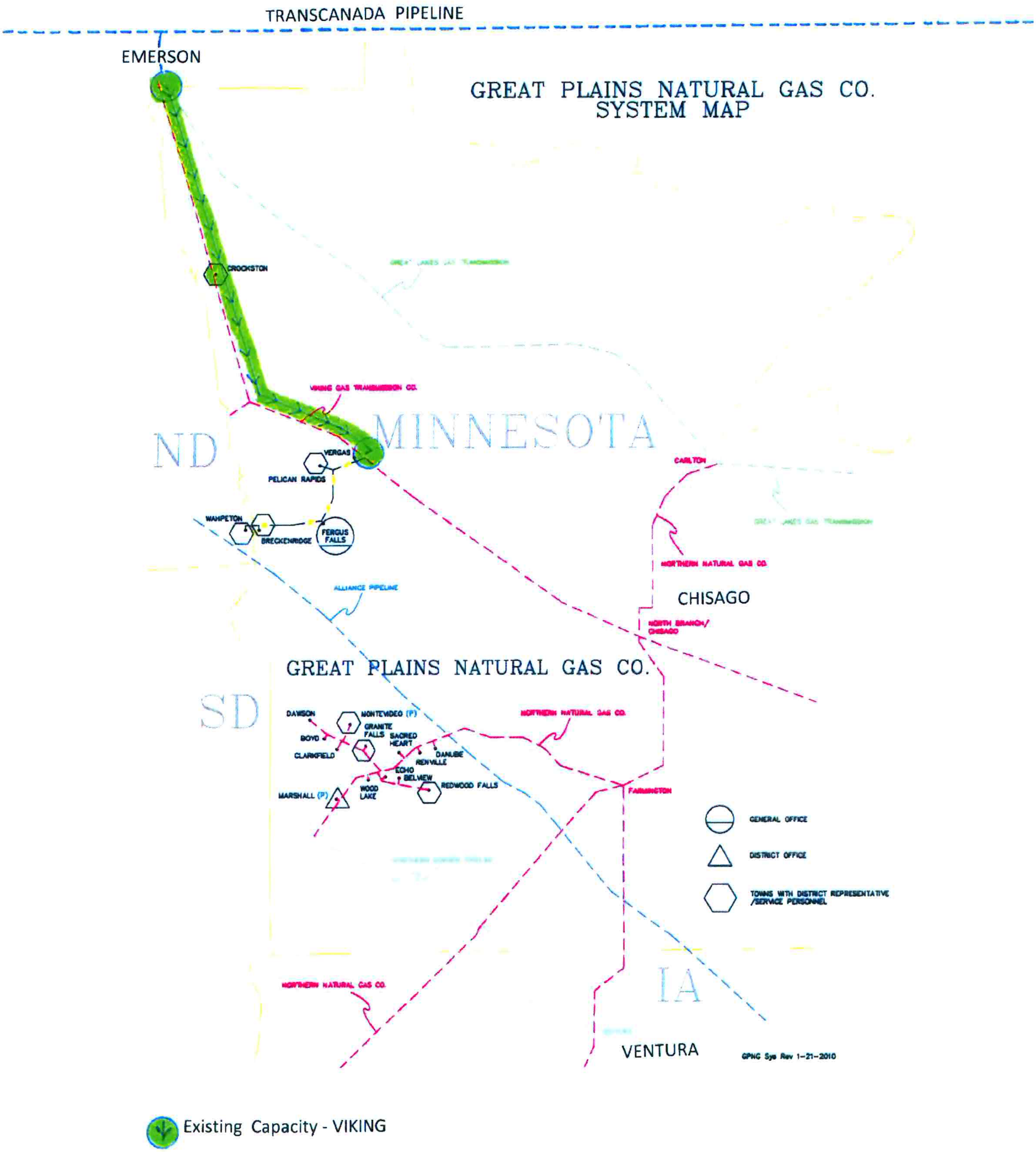
2010-2011 Heating Season G004/M-10-1164	Quantity (dk)
FT-A (12 months)	7,841
FT-A (November through March)	5,000
TFX (November through March)	3,000
FT-A (November through March)	3,000
LMS Demand	2,500
Brokered Reservation Charge (Emerson)	13,015
Heating Season Total Capacity	15,841
Non-Heating Season Total Capacity	7,841
Total Entitlement (Including Peak Shaving)	15,841
Total Annual Transportation	7,841
Total Season Transportation	8,000
Total Percent Seasonal	50.50%

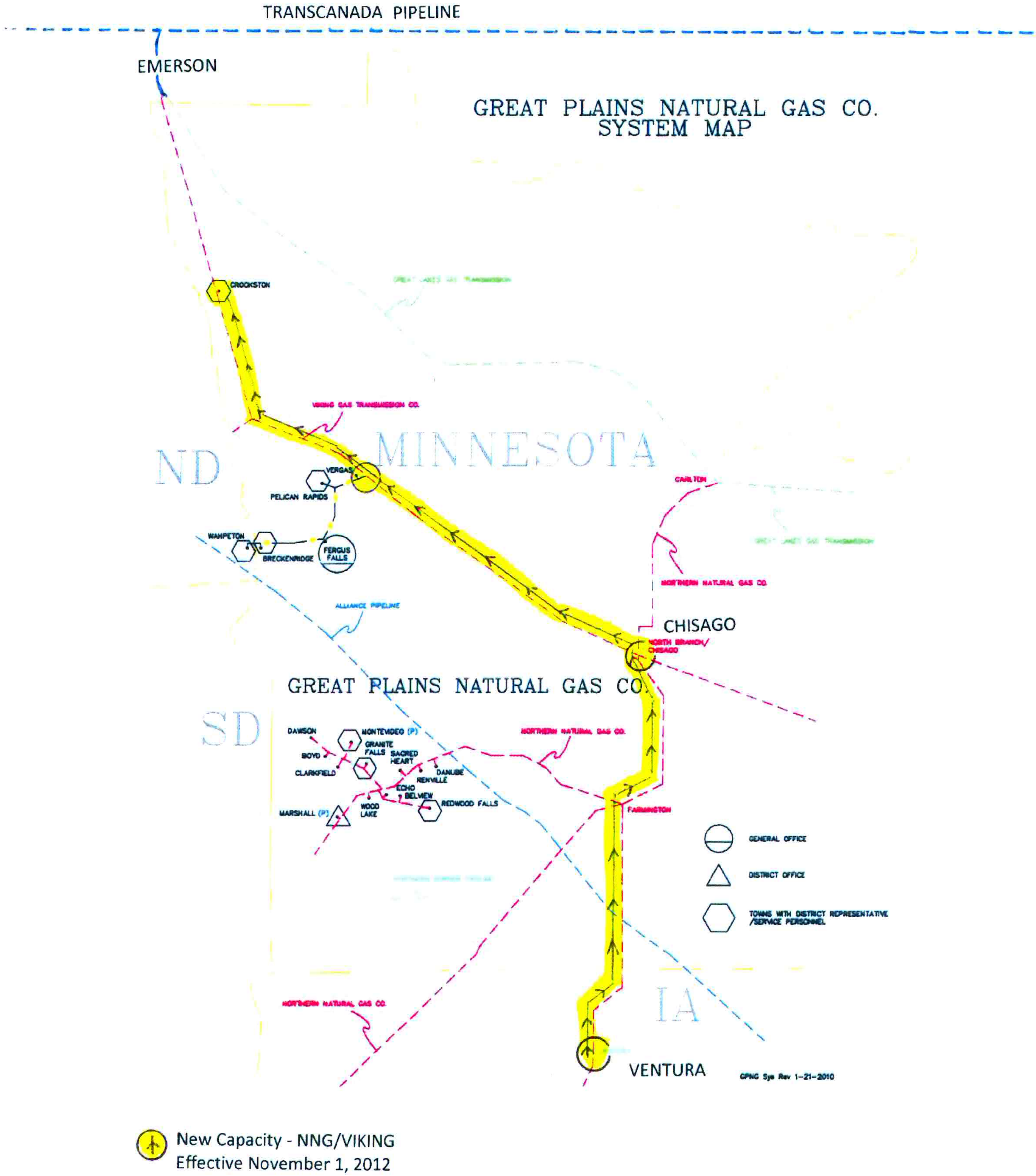
2011-2012 Heating Season G004/M-11-1075	Quantity (dk)
FT-A (12 months)	7,841
FT-A (November through March)	5,000
TFX (November through March)	2,000
FT-A (November through March)	2,000
LMS Demand	2,500
Brokered Reservation Charge (Emerson)	13,015
Heating Season Total Capacity	14,841
Non-Heating Season Total Capacity	7,841
Total Entitlement (Including Peak Shaving)	14,841
Total Annual Transportation	7,841
Total Season Transportation	7,000
Total Percent Seasonal	47.17%

2012-2013 Heating Season G004/M-12-	Quantity (dk)	Difference
FT-A (12 months)	8,000	159
FT-A (November through March)	5,000	-
TFX (November through March)	2,000	-
TFX (12 months)	13,000	13,000
FT-A (November through March)	2,000	-
LMS Demand	2,500	-
Brokered Reservation Charge (Emerson)	-	(13,015)
Heating Season Total Capacity	15,000	159
Non-Heating Season Total Capacity	8,000	159
Total Entitlement (Including Peak Shaving)	15,000	159
Total Annual Transportation	8,000	159
Total Season Transportation	7,000	-
Total Percent Seasonal	46.67%	-0.50%

GREAT PLAINS NATURAL GAS CO.
DEMAND PROFILE
SOUTH DISTRICT

2010-2011 Heating Season G004/M-10-1164	Quantity (dk)	2011-2012 Heating Season G004/M-11-1075	Quantity (dk)	2012-2013 Heating Season G004/M-12-	Quantity (dk)	Difference
TF-12 Base	5,500	TF-12 Base	5,644	TF-12 Base	5,644	-
TF-12 Variable	2,035	TF-12 Variable	1,891	TF-12 Variable	1,891	-
FT-A (April through October)	5,000	FT-A (April through October)	5,000	FT-A (April through October)	5,000	-
TF-5 (November through March)	3,410	TF-5 (November through March)	3,410	TF-5 (November through March)	3,410	-
TFX (November through March)	3,700	TFX (November through March)	4,700	TFX (November through March)	4,700	-
Peak Shaving	1,380	Peak Shaving	-	Peak Shaving	-	-
SMS	2,500	SMS	2,500	SMS	2,500	-
FDD-1 Reservation	4,640	FDD-1 Reservation	4,640	FDD-1 Reservation	4,640	-
Heating Season Total Capacity	16,025	Heating Season Total Capacity	15,645	Heating Season Total Capacity	15,645	-
Non-Heating Season Total Capacity	12,535	Non-Heating Season Total Capacity	12,535	Non-Heating Season Total Capacity	12,535	-
Total Entitlement (Including Peak Shaving)	16,025	Total Entitlement (Including Peak Shaving)	15,645	Total Entitlement (Including Peak Shaving)	15,645	-
Total Annual Transportation	7,535	Total Annual Transportation	7,535	Total Annual Transportation	7,535	-
Total Season Transportation	7,110	Total Season Transportation	8,110	Total Season Transportation	8,110	-
Percent TF-5	31.16%	Percent TF-5	31.16%	Percent TF-5	31.16%	0.00%
Total Percent Seasonal	44.37%	Total Percent Seasonal	51.84%	Total Percent Seasonal	51.84%	0.00%


TRANSCANADA PIPELINE
EMERSON
GREAT PLAINS NATURAL GAS CO.
SYSTEM MAP
CROOKSTON
VIKING GAS TRANSMISSION CO.
ND
MINNESOTA
VERGAS
PELICAN RAPIDS
WAHPETON
BRECKENRIDGE
FERGUS FALLS
CARLTON
NORTHERN NATURAL GAS CO.
CHISAGO
NORTH BRANCH/ CHISAGO
ALLIANCE PIPELINE
GREAT PLAINS NATURAL GAS CO.
SD
DAWSON
MONTEVIDEO (P)
BOYD
GRANITE FALLS
SACRED HEART
CLARKFIELD
DANUBE
RENVILLE
ECHO
BELVIEW
REDWOOD FALLS
MARSHALL (P)
WOOD LAKE
NORTHERN NATURAL GAS CO.
FARMINGTON
GENERAL OFFICE
DISTRICT OFFICE
TOWNS WITH DISTRICT REPRESENTATIVE /SERVICE PERSONNEL
IA
NORTHERN NATURAL GAS CO.
VENTURA
GPNG Sys Rev 1-21-2010
Existing Capacity - VIKING


TRANSCANADA PIPELINE
EMERSON
GREAT PLAINS NATURAL GAS CO.
SYSTEM MAP
CROOKSTON
VIKING GAS TRANSMISSION CO.
ND
MINNESOTA
VERGAS
PELICAN RAPIDS
WAHPETON
BRECKENRIDGE
FERGUS FALLS
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ALLIANCE PIPELINE
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NORTH BRANCH/CHISAGO
GREAT PLAINS NATURAL GAS CO.
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MARSHALL (P)
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NORTHERN NATURAL GAS CO.
FARMINGTON
GENERAL OFFICE
DISTRICT OFFICE
TOWNS WITH DISTRICT REPRESENTATIVE /SERVICE PERSONNEL
IA
NORTHERN NATURAL GAS CO.
VENTURA
GPNG Sys Rev 1-21-2010
New Capacity - NNG/VIKING
Effective November 1, 2012

GREAT PLAINS NATURAL GAS CO.
TRANSPORTATION CONTRACT COST ANALYSIS

	Cost
Scenario 1	
Northern Natural Gas Transportation from Ventura to Chisago and Viking Backhaul Transportation (Long-term)	$2,080,644
Scenario 2	
New NOVA/TransCanada Transportation and existing Viking Forwardhaul Transportation	5,325,878
Scenario 3	
A) 50% Canadian Transportation/ 50% Northern Natural Gas Transportation	3,715,945
B) 40% Canadian Transportation/ 60% Northern Natural Gas Transportation	4,006,855
Scenario 4	
Continuation of ProGas Contract	6,282,479

Great Plains Natural Gas Co. - Scenario #1
Utilizing Northern Natural Gas Transportation from
Ventura to Chisago and Viking Backhaul Transportation (Long-term)

Demand Charges - NNG TFX Transportation - 10 year term		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
13,000 dk/day @ $15.153 (Nov-Mar)		984,945	196,989	196,989	196,989	0	0	0	0	0	0	0	196,989	196,989
13,000 dk/day @ $5.683 (Apr-Oct)		517,153	0	0	0	73,879	73,879	73,879	73,879	73,879	73,879	73,879	0	0
Sub-Total	$	**1,502,098**	196,989	196,989	196,989	73,879	73,879	73,879	73,879	73,879	73,879	73,879	196,989	196,989

Demand Charges - Viking Backhaul Contract Term of 5 or more years (Lowest rate)			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
5,000 dk/day @ $3.4671		208,032	17,336	17,336	17,336	17,336	17,336	17,336	17,336	17,336	17,336	17,336	17,336	17,336
8,000 dk/day @ $3.4671		332,844	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737
2,000 dk/day @ $3.7671 (Nov-Mar) (Existing Short-Term)		37,670	7,534	7,534	7,534	0	0	0	0	0	0	0	7,534	7,534
Sub-Total	$	**578,546**	52,607	52,607	52,607	45,073	45,073	45,073	45,073	45,073	45,073	45,073	52,607	52,607
TOTAL	$	**2,080,644**												

Great Plains Natural Gas Co. - Scenario #2
Based on New NOVA/TransCanada Transportation
and existing Viking Forwardhaul Transportation

Canadian Demand Charges - $/US	US$/MMBtu	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NOVA Demand Charges - FT-D - 13,000 MMBtu/day	6.6627	1,039,380	86,615	86,615	86,615	86,615	86,615	86,615	86,615	86,615	86,615	86,615	86,615	86,615
NOVA FT-D Fuel	0.043885	6,840	570	570	570	570	570	570	570	570	570	570	570	570
TransCanada Pipeline Demand Charges	23.27905	3,631,536	302,628	302,628	302,628	302,628	302,628	302,628	302,628	302,628	302,628	302,628	302,628	302,628
TransCanada Pipeline Pressure Surcharge	0.100706	15,708	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309
Sub-Total		**4,693,464**	391,122	391,122	391,122	391,122	391,122	391,122	391,122	391,122	391,122	391,122	391,122	391,122

Demand Charges - Viking Forwardhaul		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
7,841 dk/day @ $3.4671(Jan-Dec) - AF0010		326,232	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186
4,500 dk/day @ $4.5871(Jan-Dec) - AF0091		247,704	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642
500 dk/day @ $3.4671(Jan-Dec) - AF0092		20,808	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734
2,000 dk/day @ $3.7671 (Nov-Mar) (Existing)		37,670	7,534	7,534	7,534	0	0	0	0	0	0	0	7,534	7,534
Sub-Total		**632,414**	57,096	57,096	57,096	49,562	49,562	49,562	49,562	49,562	49,562	49,562	57,096	57,096
	TOTAL	**5,325,878**												

Great Plains Natural Gas Co. - Scenario #3
50% Canadian Transportation/ 50% NNG Transportation

Canadian Demand Charges - $/US	US$/MMBtu	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NOVA Demand Charges - FT-D - 6,500 MMBtu/day	6.5134	508,044	42,337	42,337	42,337	42,337	42,337	42,337	42,337	42,337	42,337	42,337	42,337	42,337
NOVA FT-D Fuel	0.082297	6,420	535	535	535	535	535	535	535	535	535	535	535	535
TransCanada Pipeline Demand Charges	23.89522	1,863,828	155,319	155,319	155,319	155,319	155,319	155,319	155,319	155,319	155,319	155,319	155,319	155,319
TransCanada Pipeline Pressure Surcharge	0.103372	8,064	672	672	672	672	672	672	672	672	672	672	672	672
Sub-Total		**2,386,356**	198,863	198,863	198,863	198,863	198,863	198,863	198,863	198,863	198,863	198,863	198,863	198,863

Demand Charges - NNG TFX Transportation	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
6.500 dk/day @ $15.153 (Nov-Mar)	492,475	98,495	98,495	98,495	0	0	0	0	0	0	0	98,495	98,495
6,500 dk/day @ $5.683 (Apr-Oct)	258,580	0	0	0	36,940	36,940	36,940	36,940	36,940	36,940	36,940	0	0
Sub-Total	**751,055**	98,495	98,495	98,495	36,940	36,940	36,940	36,940	36,940	36,940	36,940	98,495	98,495
Total Canada	**3,137,411**												

Demand Charges - $/U.S.- Viking	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
6,500 dk/day @ $3.4671(Jan-Dec) (5 year term) - Forwardhaul	270,432	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536
6,500 dk/day @ $3.4671(Jan-Dec) (5 year term) - Backhaul	270,432	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536	22,536
2,000 dk/day @ $3.7671 (Nov-Mar) (Existing) - Backhaul	37,670	7,534	7,534	7,534	0	0	0	0	0	0	0	7,534	7,534
Sub-Total	**578,534**	52,606	52,606	52,606	45,072	45,072	45,072	45,072	45,072	45,072	45,072	52,606	52,606
TOTAL	**3,715,945**												

Great Plains Natural Gas Co. - Scenario #3
40% Canadian Transportation/ 60% NNG Transportation

Canadian Demand Charges - $/US		US$/MMBtu	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NOVA Demand Charges - FT-D - 5,000 MMBtu/day	5,000	6.6627	399,768	33,314	33,314	33,314	33,314	33,314	33,314	33,314	33,314	33,314	33,314	33,314	33,314
NOVA FT-D Fuel	5,000	0.043885	2,633	219	219	219	219	219	219	219	219	219	219	219	219
TransCanada Pipeline Demand Charges	5,000	23.27905	1,396,740	116,395	116,395	116,395	116,395	116,395	116,395	116,395	116,395	116,395	116,395	116,395	116,395
TransCanada Pipeline Pressure Surcharge	5,000	0.100706	6,048	504	504	504	504	504	504	504	504	504	504	504	504
Sub-Total			**1,805,189**	150,432	150,432	150,432	150,432	150,432	150,432	150,432	150,432	150,432	150,432	150,432	150,432
Demand Charges - NNG TFX Transportation				**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
8,000 dk/day - Firm Transportation	8,000	16.72	1,605,120	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760
Sub-Total			**1,605,120**	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760	133,760
Total Canada			**3,410,309**												
Demand Charges - $/U.S.- Viking				**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
4,500 dk/day (Jan-Dec) (Short-term) - Forwardhaul (Zone 1-2	4,500	4.8871	263,904	21,992	21,992	21,992	21,992	21,992	21,992	21,992	21,992	21,992	21,992	21,992	21,992
500 dk/day (Jan-Dec) (Short-term) - Forwardhaul	500	3.7671	22,608	1884	1884	1884	1884	1884	1884	1884	1884	1884	1884	1884	1884
8,000 dk/day (Jan-Dec) (Long-term) - Backhaul	8,000	3.4671	332,844	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737	27,737
2,000 dk/day (Nov-Mar) (Existing) - Backhaul	2,000	3.7671	37,670	7,534	7,534	7,534	0	0	0	0	0	0	0	7,534	7,534
Sub-Total			**657,026**	59,147	59,147	59,147	51,613	51,613	51,613	51,613	51,613	51,613	51,613	59,147	59,147
		TOTAL	**4,067,335**												
Demand Charges - $/U.S.- Viking (w/ 4,500 on Zone 1-1)															
4,500 dk/day (Jan-Dec) (Short-term) - Forwardhaul (Zone 1-1	4,500	3.7671	203,424	16,952	16,952	16,952	16,952	16,952	16,952	16,952	16,952	16,952	16,952	16,952	16,952
Sub-Total			**596,546**	54,107	54,107	54,107	46,573	46,573	46,573	46,573	46,573	46,573	46,573	54,107	54,107
		TOTAL	**4,006,855**												

CURRENT PROGAS CHARGES

Canadian Demand Charges - $/US-Current	US$/MMBtu	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
DCQ - 7,947 MMBtu/day														
Nova Demand Charges														
FT-D	8.662826	826,176	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848
FT-R	8.662826	826,176	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848	68,848
NOVA FT-D Fuel	0.082297	7,848	654	654	654	654	654	654	654	654	654	654	654	654
NOVA FT-R Fuel	0.082297	7,848	654	654	654	654	654	654	654	654	654	654	654	654
TCPL Demand Costs	23.89522	2,278,872	189,906	189,906	189,906	189,906	189,906	189,906	189,906	189,906	189,906	189,906	189,906	189,906
TCPL Pressure Surcharge	0.103372	9,864	822	822	822	822	822	822	822	822	822	822	822	822
Cost of Service (7,947*days in month*.0316)	0.0316	90,408	7,534	7,534	7,534	7,534	7,534	7,534	7,534	7,534	7,534	7,534	7,534	7,534
Sub-Total		**4,047,192**	337,266	337,266	337,266	337,266	337,266	337,266	337,266	337,266	337,266	337,266	337,266	337,266
IDCQ - 5068 MMBtu/day														
Nova Demand Charges														
FT-D	8.662826	307,321	43,903	43,903	43,903	43,903	0	0	0	0	0	43,903	43,903	43,903
FT-R	8.662826	307,321	43,903	43,903	43,903	43,903	0	0	0	0	0	43,903	43,903	43,903
NOVA FT-D Fuel	0.082297	2,919	417	417	417	417	0	0	0	0	0	417	417	417
NOVA FT-R Fuel	0.082297	2,919	417	417	417	417	0	0	0	0	0	417	417	417
TCPL Demand Costs	23.89522	847,707	121,101	121,101	121,101	121,101	0	0	0	0	0	121,101	121,101	121,101
TCPL Pressure Surcharge	0.103372	3,668	524	524	524	524	0	0	0	0	0	524	524	524
Cost of Service (5,068*days in month*.0316)	0.0316	33,628	4,804	4,804	4,804	4,804	0	0	0	0	0	4,804	4,804	4,804
Winter Surcharge		78,555	15,711	15,711	15,711	0	0	0	0	0	0	0	15,711	15,711
Sub-Total		**1,584,038**	230,780	230,780	230,780	215,069	0	0	0	0	0	215,069	230,780	230,780
Total Canada		**5,631,230**												

Demand Charges - Viking FT Current	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
3,000 dk/day @ $3.7671 (Nov-Mar) - AF0049	56,505	11,301	11,301	11,301	0	0	0	0	0	0	0	11,301	11,301
7,841 dk/day @ $3.4671(Jan-Dec) - AF0010	326,232	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186	27,186
4,500 dk/day @ $4.5871(Jan-Dec) - AF0091	247,704	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642	20,642
500 dk/day @ $3.4671(Jan-Dec) - AF0092	20,808	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734	1,734
Sub-Total	**651,249**	60,863	60,863	60,863	49,562	49,562	49,562	49,562	49,562	49,562	49,562	60,863	60,863
TOTAL	**6,282,479**												

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2012 - 2013 HEATING SEASON
DESIGN DAY - NOVEMBER 2012

Area	Customer Factors 1/ Dk/day	Customer Factors 1/ Dk/DD	Customer Factors 1/ RSqr	Design HDD 2/	No. of Customers 3/	Projected Customers 4/	Peak/ Customer	Projected Peak Day (dk)	L&UA 5/	Projected Design	Capacity	Reserve
Crookston	0.05079	0.01232	0.98304	96	2,421	2,434	1.23351	3,002	21	3,023		
North 4	0.05746	0.01289	0.98929	91	6,821	6,876	1.23045	8,461	60	8,521		
Wahpeton	0.09650	0.01299	0.97997	91	2,081	2,097	1.27859	2,681	19	2,700		
Total North District					11,323	11,407		14,144	100	14,244	15,000	5.3%
South 13	0.05292	0.01477	0.98843	83	11,500	11,531	1.27883	14,746	104	14,850	15,645	5.4%
Total					22,823	22,938		28,890	204	29,094	30,645	5.3%

1/ Use per customer factors based on regression analysis for the 36 months ending March 2012.
2/ Design Heating Degree Days Base 60 degrees F.
3/ Reflects monthly average December 2011 - February 2012
4/ Customer growth is based on regression analysis for the 36 months ending March 2012 with composite growth rates of, Crookston = 0.28%, North = 0.77%, Wahpeton = 0.62%, South = 0.25%.
5/ Lost and Unaccounted for Gas percentage of 0.7%.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2012
NORTH DISTRICT

	Last Rate Case 1/	Last Demand Change 2/	June 2012 PGA 3/	Proposed 4/	% Change from Last Rate Case	% Change from Last Demand Change	% Change from June 2012 PGA	Change from June 2012 PGA
Residential								
Commodity Cost of Gas	$5.6571	$3.4655	$2.2406	$2.2406	-60.4%	-35.3%	0.0%	$0.0000
Demand Cost of Gas	1.9635	4.0733	3.9336	1.5409	-21.5%	-62.2%	-60.8%	(2.3927)
Commodity Margin 5/	1.7671	1.7740	1.7689	1.7689	0.1%	-0.3%	0.0%	0.0000
Total Rate	9.3877	9.7848	7.9431	5.5504	-40.9%	-43.3%	-30.1%	(2.3927)
Average Annual Usage (dk)	103.8	103.8	103.8	103.8				
Average Annual Cost of Gas	$974.44	$1,015.66	$824.49	$576.13	-40.9%	-43.3%	-30.1%	($248.36)
Firm General Service								
Commodity Cost of Gas	$5.6571	$3.4655	$2.2406	$2.2406	-60.4%	-35.3%	0.0%	$0.0000
Demand Cost of Gas	1.9635	4.0733	3.9336	1.5409	-21.5%	-62.2%	-60.8%	(2.3927)
Commodity Margin	1.4471	1.4577	1.4553	1.4553	0.6%	-0.2%	0.0%	0.0000
Total Rate	9.0677	9.4685	7.6295	5.2368	-42.2%	-44.7%	-31.4%	(2.3927)
Average Annual Usage (dk)	375.7	375.7	375.7	375.7				
Average Annual Cost of Gas	$3,406.73	$3,557.32	$2,866.42	$1,967.48	-42.2%	-44.7%	-31.4%	($898.94)

Customer Class	Commodity Change ($/dk)	Commodity Change (Percent)	Demand Change ($/dk)	Demand Change (Percent)	Total Change ($/dk)	Total Change (Percent)	Average Annual Bill Change
Residential	$0.0000	0.0%	($2.3927)	-60.8%	($2.3927)	-30.1%	($248.36)
Firm General Service	0.0000	0.0%	(2.3927)	-60.8%	(2.3927)	-31.4%	(898.94)

1/ Base Cost of Gas Effective January 2007 in Docket No. G004/MR-06-1141.
2/ Demand in Docket No. G004/M-11-1075, effective November 1, 2011.
3/ June 2012 PGA.
4/ Proposed in this docket, G004/M-12-____ effective November 1, 2012.
5/ Includes CCRA and GAP.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2012
SOUTH DISTRICT

	Last Rate Case 1/	Last Demand Change 2/	June 2012 PGA 3/	Proposed 4/	% Change from Last Rate Case	% Change from Last Demand Change	% Change from June 2012 PGA	Change from June 2012 PGA
Residential								
Commodity Cost of Gas	$5.9550	$3.6551	$2.4821	$2.4821	-58.3%	-32.1%	0.0%	$0.0000
Demand Cost of Gas	1.2338	1.4897	1.4952	1.1906	-3.5%	-20.1%	-20.4%	(0.3046)
Commodity Margin 5/	1.4279	1.3892	1.3849	1.3849	-3.0%	-0.3%	0.0%	0.0000
Total Rate	8.6167	6.8945	5.3622	5.0576	-41.3%	-26.6%	-5.7%	(0.3046)
Average Annual Usage (dk)	88.2	88.2	88.2	88.2				
Average Annual Cost of Gas	$759.99	$608.09	$472.95	$446.08	-41.3%	-26.6%	-5.7%	(26.8700)
Firm General Service								
Commodity Cost of Gas	$5.9550	$3.6551	$2.4821	$2.4821	-58.3%	-32.1%	0.0%	0.0000
Demand Cost of Gas	1.2338	1.4897	1.4952	1.1906	-3.5%	-20.1%	-20.4%	(0.3046)
Commodity Margin	1.1775	1.1388	1.1371	1.1371	-3.4%	-0.1%	0.0%	0.0000
Total Rate	8.3663	6.6441	5.1144	4.8098	-42.5%	-27.6%	-6.0%	(0.3046)
Average Annual Usage (dk)	340.9	340.9	340.9	340.9				
Average Annual Cost of Gas	$2,852.07	$2,264.97	$1,743.50	$1,639.66	-42.5%	-27.6%	-6.0%	(103.8400)

Customer Class	Commodity Change ($/dk)	Commodity Change (Percent)	Demand Change ($/dk)	Demand Change (Percent)	Total Change ($/dk)	Total Change (Percent)	Average Annual Bill Change
Residential	$0.0000	0.0%	($0.3046)	-20.4%	($0.3046)	-5.7%	($26.8700)
Firm General Service	0.0000	0.0%	(0.3046)	-20.4%	(0.3046)	-6.0%	(103.8400)

1/ Base Cost of Gas Effective January 2007 in Docket No. G004/MR-06-1141.
2/ Demand in Docket No. G004/M-11-1075, effective November 1, 2011.
3/ June 2012 PGA.
4/ Proposed in this docket, G004/M-12-____ effective November 1, 2012.
5/ Includes CCRA and GAP.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT ANALYSIS
NORTH DISTRICT

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Storage + Peak Shaving			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Heating Season	Number of Customers	Change From Previous Year	% Change From Previous Year	Design Day (dk)	Change From Previous Year	% Change From Previous Year	Total Entitlement (dk)	Change From Previous Year	% Change From Previous Year	% of Reserve Margin [(7)-(4)]/(4)
2012-2013	11,407	177	1.58%	14,244	176	1.25%	15,000	159	1.07%	5.31%
2011-2012	11,230	48	0.43%	14,068	(96)	-0.68%	14,841	(1,000)	-6.31%	5.49%
2010-2011	11,182	(12)	-0.11%	14,164	(248)	-1.72%	15,841	0	0.00%	11.84%
2009-2010	11,194	8	0.07%	14,412	(37)	-0.26%	15,841	(1,000)	-5.94%	9.92%
2008-2009	11,186	41	0.37%	14,449	(413)	-2.78%	16,841	0	0.00%	16.55%
2007-2008	11,145	28	0.25%	14,862	(289)	-1.91%	16,841	0	0.00%	13.32%
2006-2007	11,117	(64)	-0.57%	15,151	(673)	-4.25%	16,841	0	0.00%	11.15%
2005-2006	11,181	81	0.73%	15,824	(49)	-0.31%	16,841	0	0.00%	6.43%
2004-2005	11,100	25	0.23%	15,873	(121)	-0.76%	16,841	0	0.00%	6.10%
2003-2004 1/	11,075	2,375	27.30%	15,994	2,559	19.05%	16,841	4,154	32.74%	5.30%
2002-2003	8,700	180	2.11%	13,435	(1,231)	-8.39%	12,687	(2,780)	-17.97%	-5.57%
2001-2002	8,520	19	0.22%	14,666	212	1.47%	15,467	0	0.00%	5.46%
2000-2001	8,501	304	3.71%	14,454	0	0.00%	15,467	0	0.00%	7.01%
1999-2000	8,197	82	1.01%	14,454	618	4.47%	15,467	0	0.00%	7.01%
1998-1999	8,115	227	2.88%	13,836	244	1.80%	15,467	0	0.00%	11.79%
1997-1998	7,888	215	2.80%	13,592	2,415	21.61%	15,467	3,950	34.30%	13.79%
1996-1997	7,673	267	3.61%	11,177	379	3.51%	11,517	1,459	14.51%	3.04%
1995-1996	7,406			10,798			10,058			-6.85%
Annual Average			2.74%			1.89%			3.08%	7.06%

	Firm Peak Day Sendout						
	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Heating Season	Firm Peak Day Sendout (dk)	Change From Previous Year	% Change From Previous Year	Excess Per Customer [(7)-(4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak Day Sendout per Customer (11)/(1)
2012-2013				0.0663	1.2487	1.3150	
2011-2012	8,441	(2,617)	-23.67%	0.0688	1.2527	1.3215	0.7516
2010-2011	11,058	2,134	23.91%	0.1500	1.2667	1.4167	0.9889
2009-2010	8,924	(769)	-7.93%	0.1277	1.2875	1.4151	0.7972
2008-2009	9,693	(348)	-3.47%	0.2138	1.2917	1.5055	0.8665
2007-2008	10,041	451	4.70%	0.1776	1.3335	1.5111	0.9009
2006-2007	9,590	43	0.45%	0.1520	1.3629	1.5149	0.8626
2005-2006	9,547	(923)	-8.82%	0.0910	1.4153	1.5062	0.8539
2004-2005	10,470	(942)	-8.25%	0.0872	1.4300	1.5172	0.9432
2003-2004	11,412	1,606	16.38%	0.0765	1.4442	1.5206	1.0304
2002-2003	9,806	(3,572)	-26.70%	(0.0860)	1.5443	1.4583	1.1271
2001-2002	13,378	1,699	14.55%	0.0940	1.7214	1.8154	1.5702
2000-2001	11,679	(1,699)	-12.70%	0.1192	1.7003	1.8194	1.3738
1999-2000	13,378	2,196	19.64%	0.1236	1.7633	1.8869	1.6321
1998-1999	11,182	(748)	-6.27%	0.2010	1.7050	1.9060	1.3779
1997-1998	11,930	267	2.29%	0.2377	1.7231	1.9608	1.5124
1996-1997	11,663	551	4.96%	0.0443	1.4567	1.5010	1.5200
1995-1996	11,112			(0.0999)	1.4580	1.3581	1.5004
Annual Average			-0.68%	0.1025	1.4670	1.5694	1.1535

1/ Crookston was consolidated with the North District in 2003.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT ANALYSIS
SOUTH DISTRICT

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Storage + Peak Shaving			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Heating Season	Number of Customers	Change From Previous Year	% Change From Previous Year	Design Day (dk)	Change From Previous Year	% Change From Previous Year	Total Entitlement (dk)	Change From Previous Year	% Change From Previous Year	% of Reserve Margin [(7)-(4)]/(4)
2012-2013	11,531	(13)	-0.11%	14,850	(18)	-0.12%	15,645	0	0.00%	5.35%
2011-2012	11,544	(8)	-0.07%	14,868	(297)	-1.96%	15,645	(380)	-2.37%	5.23%
2010-2011	11,552	10	0.09%	15,165	(267)	-1.73%	16,025	(1,170)	-6.80%	5.67%
2009-2010	11,542	77	0.67%	15,432	156	1.02%	17,195	(170)	-0.98%	11.42%
2008-2009	11,465	8	0.07%	15,276	(301)	-1.93%	17,365	0	0.00%	13.68%
2007-2008	11,457	(27)	-0.24%	15,577	(117)	-0.75%	17,365	0	0.00%	11.48%
2006-2007	11,484	(224)	-1.91%	15,694	(699)	-4.26%	17,365	0	0.00%	10.65%
2005-2006	11,708	(92)	-0.78%	16,393	(336)	-2.01%	17,365	0	0.00%	5.93%
2004-2005	11,800	60	0.51%	16,729	92	0.55%	17,365	0	0.00%	3.80%
2003-2004	11,740	40	0.34%	16,637	(413)	-2.42%	17,365	0	0.00%	4.38%
2002-2003	11,700	76	0.65%	17,050	(2,058)	-10.77%	17,365	(2,600)	-13.02%	1.85%
2001-2002	11,624	189	1.65%	19,108	7	0.04%	19,965	0	0.00%	4.49%
2000-2001	11,435	(41)	-0.36%	19,101	0	0.00%	19,965	0	0.00%	4.52%
1999-2000	11,476	280	2.50%	19,101	340	1.81%	19,965	0	0.00%	4.52%
1998-1999	11,196	(25)	-0.22%	18,761	374	2.03%	19,965	0	0.00%	6.42%
1997-1998	11,221	306	2.80%	18,387	431	2.40%	19,965	2,000	11.13%	8.58%
1996-1997	10,915	235	2.20%	17,956	353	2.01%	17,965	1,008	5.94%	0.05%
1995-1996	10,680			17,603			16,957			-3.67%
Annual Average			0.46%			-0.95%			-0.36%	5.80%

	Firm Peak Day Sendout			(14)	(15)	(16)	(17)
	(11)	(12)	(13)				
Heating Season	Firm Peak Day Sendout (dk)	Change From Previous Year	% Change From Previous Year	Excess Per Customer [(7)-(4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak Day Sendout per Customer (11)/(1)
2012-2013				0.0689	1.2878	1.3568	
2011-2012	10,268	(1,652)	-13.86%	0.0673	1.2879	1.3552	0.8895
2010-2011	11,920	(692)	-5.49%	0.0744	1.3128	1.3872	1.0319
2009-2010	12,612	(962)	-7.09%	0.1527	1.3370	1.4898	1.0927
2008-2009	13,574	888	7.00%	0.1822	1.3324	1.5146	1.1840
2007-2008	12,686	401	3.26%	0.1561	1.3596	1.5157	1.1073
2006-2007	12,285	(789)	-6.03%	0.1455	1.3666	1.5121	1.0697
2005-2006	13,074	(996)	-7.08%	0.0830	1.4002	1.4832	1.1167
2004-2005	14,070	(626)	-4.26%	0.0539	1.4177	1.4716	1.1924
2003-2004	14,696	425	2.98%	0.0620	1.4171	1.4791	1.2518
2002-2003	14,271	2,151	17.75%	0.0269	1.4573	1.4842	1.2197
2001-2002	12,120	(2,724)	-18.35%	0.0737	1.6438	1.7176	1.0427
2000-2001	14,844	(1,921)	-11.46%	0.0756	1.6704	1.7460	1.2981
1999-2000	16,765	828	5.20%	0.0753	1.6644	1.7397	1.4609
1998-1999	15,937	(133)	-0.83%	0.1075	1.6757	1.7832	1.4235
1997-1998	16,070	115	0.72%	0.1406	1.6386	1.7793	1.4321
1996-1997	15,955	(418)	-2.55%	0.0008	1.6451	1.6459	1.4617
1995-1996	16,373			(0.0605)	1.6482	1.5877	1.5331
Annual Average			-2.51%	0.0826	1.4757	1.5583	1.2240