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

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June 30, 2016

Mr. Daniel P. Wolf
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-16-___

Dear Mr. Wolf:

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 2016-2017 winter heating season.

Great Plains requested Commission approval to combine the North and South Purchased Gas Cost (PGA) districts in Docket No. G004/MR-15-879, currently pending before the Commission. The analysis provided in this Demand Entitlement Filing (DEQ) is based on the two historic PGA districts.

Great Plains is requesting incremental capacity on a FT-A Seasonal contract from Viking, as shown on Exhibit A. Great Plains requests that the additional capacity be effective November 1, 2016.

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

Exhibit A – Demand Profile
Exhibit B – Design Day Capacity
Exhibit C – Rate Impacts
Exhibit D – Demand Entitlement Analysis

Exhibit A - Demand Profile

In the North District, Great Plains has contracted for capacity of 5,000 dk per day with the receipt point of Emerson and 10,000 dk per day with the receipt point of Chisago, both on the Viking pipeline system.

As noted in the update to Docket No. G004/M-15-645 provided on October 29, 2015, Great Plains procured 700 dk per day of seasonal capacity from Viking along with a contract for 730 dk of firm gas to be delivered to Vikings' Chisago receipt point from a current gas supplier for the 2015-2016 heating season. These contracts have expired and Great Plains proposes to replace the capacity and delivered gas provided under the 2015-2016 contracts with 1,350 dk per day of incremental capacity on Viking.

The North District capacity for the 2016-2017 heating season will increase 650 dk from the 2015-2016 heating season and Great Plains projects a 5.1 percent reserve for the upcoming heating season, including the additional capacity. This capacity level is sufficient to meet the estimated peak day demand.

Table 1: North PGA District Proposed Demand Costs

Interstate Pipelines	Volumes (1) Dth/day	Rates (2) $	Months (3)	Demand Costs (4) $
Viking				
FT-A Zone 1-1 (Cat 3)	8,000	4.3706	12	419,578
FT-A Zone 1-1 (Cat 1)	5,000	4.7507	5	118,768
FT-A Seasonal	2,000	4.7507	5	47,507
Proposed: FT-A Seasonal	1,350	4.7507	5	32,067
NNG				
TFX - Seasonal	2,000	15.1530	5	151,530
TFX - Winter	13,000	15.1530	5	984,945
TFX - Summer	13,000	5.6830	7	517,153
Total Demand Costs				2,271,548

In the South District, as noted in the update to Docket No. G004/M-15-645 submitted on October 29, 2015, Great Plains entered into a 10-year agreement for 2,000 dk per day annual capacity available on Northern Natural's system and released 1,300 dk per day of excess capacity for the 2015-2016 heating season to a third party marketer. This capacity release has expired and Great Plains proposes to again release 1,300 dk per day of excess capacity for 2016-2017 heating season for a net capacity of 17,845 dk per day. A 6.0 percent reserve is projected for the upcoming heating season.

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, 2016 and Great Plains will provide a report to the Commission regarding the amount of the TF12 Base and TF12 Variable in place for the 2016-2017 season.

Table 2: South PGA District Proposed Demand Costs

Interstate Pipelines	Volumes (1) Dth/day	Rates (2) $	Months (3)	Demand Costs (4) $
Viking				
FT-A Zone 1-1 (Cat 1)	5,000	4.7507	7	166,275
NNG				
TF12 Base - Summer	4,604	5.6830	7	183,152
TF12 Base - Winter	4,604	10.2300	5	235,495
TF12 Variable - Summer	2,931	5.6830	7	116,598
TF12 Variable - Winter	2,931	13.8660	5	203,206
TF5	3,410	15.1530	5	258,359
TFX - Summer	2,000	5.6830	7	79,562
TFX - Winter	7,200	15.1530	5	545,508
TFX Negotiated Contract - Winter	1,000	26.8918	5	134,459
Proposed: TFX Capacity Release	(1,300)	1/	5	(43,186)
FDD-1 Reservation	4,640	1.7140	12	95,436
Total Demand Costs				1,974,864

1/ Proposed capacity release contract terms are 1,300 dk/day at $0.22/dk for the period November 1, 2016 through March 31, 2017.

Great Plains' analyses indicate that with the addition of 650 dk per day of seasonal capacity in the North and no change of capacity in the South, it will have adequate capacity to serve its firm service customers in the 2016-2017 heating season. Prior to the heating season, Great Plains will review the reserve margins to ensure adequate capacity is available to meet the projected peak day demand.

The options available include balancing the reserve capacity of the North and South Districts, contracting for additional seasonal and/or annual firm transportation capacity, or monthly gate station deliveries from marketers on the Northern Natural and/or Viking pipeline systems.

Finally, pages 2 and 3 of Exhibit A show the demand profile history for the 2014-2015, 2015-2016 and the proposed 2016-2017 heating seasons.

Exhibit B – 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 B.

In compliance with the determinations made in 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 in the North District. The calculations are consistent with the design day methodologies accepted by the Commission in its Order dated January 9, 2014 in Docket No. G004/M-13-566. Based on the study and Great Plains' proposed capacity levels, Great Plains is anticipating a reserve margin of 5.1 percent in the North District and 6.0 percent in the South District for a total reserve margin of 5.5 percent.

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 continues to see interest for natural gas throughout its service territory and anticipates additional growth of this reasonably priced clean burning fuel. Great Plains will continue to monitor customer growth and related increase in demand as well as the offsetting effect of conservation.

As stated above, Great Plains filed to combine the North and South PGA districts in Docket No. G004/MR-15-879. If approved by the Minnesota PUC, the combination of the North and South districts will:

- Provide better utilization of transportation capacity currently under contract.
- Provide better utilization of storage assets which currently are used only for the South District.
- Provide better utilization of current gas contracts to serve the North and South Districts.
- Provide more effective management of the North and South District's reserve margin.

Exhibit C – Rate Impacts

Exhibit C shows the impacts to customers due to the capacity changes discussed above. There is a decrease of 0.9 percent in the demand component for firm customers in the North District based on the proposed capacity levels and current pricing and no change in the demand component for firm customers in the South District from the rates in effect in June 2016. The estimated rate impacts are also based on the availability of seasonal contracts for the incremental capacity and the ability to contract for the capacity release with a third party marketer or a transport customer.

The total customer impact of the updated demand profile compared to rates effective June 2016 is a decrease of $0.0151 per dk. Please see Table 3 below for the annual rate impacts for the North District reflecting the changes noted in Exhibit A above.

Table 3: North PGA District Proposed Demand Costs

Filing Date	Residential Customer (103.8 Dk)	Total Change Res (%)	Firm General Service (375.7 Dk)	Total Change FGS (%)
June 30, 2016	($1.56)	-0.9	($5.68)	-0.9

The total customer impact of the updated demand profile remains unchanged from the rates effective June 2016. Please see Table 4 below for the annual rate impacts for the South District.

Table 4: South PGA District Proposed Demand Costs

Filing Date	Residential Customer (88.2 Dk)	Total Change Res (%)	Firm General Service (340.9 Dk)	Total Change FGS (%)
June 30, 2016	$0.00	0.0	$0.00	0.0

Exhibit D – Demand Entitlement Analysis

Exhibit D reflects the historical design day requirement, total entitlement and peak day design, entitlement and firm sendout per customer for the 1995-1996 to the 2016-2017 heating seasons.

If you have any questions regarding this filing, please contact me at (701) 222-7856, or Brian M. Meloy, at (612) 335-1451.

Sincerely,

/s/ *Tamie A. Aberle*

Tamie A. Aberle
Director of Regulatory Affairs

cc: Brian M. Meloy

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2016 - 2017 HEATING SEASON
DEMAND PROFILE EFFECTIVE NOVEMBER 1, 2016

Type of Capacity or Entitlement	Current Amount	Proposed Change	Proposed Amount	Contract Length	Expiration Date
Demand Profile for North District (dk) 1/					
FT-A	8,000	0	8,000	5 years	10/31/17
FT-A - Zone 1-1 (November - March)	5,000	0	5,000	1 year	10/31/17
FT-A Seasonal (November - March)	2,000	0	2,000	1 year	10/31/17
Proposed: FT-A Seasonal (November - March)	0	1,350	1,350	5 months	3/31/17
FT-A Seasonal (November - March)	700	(700)	0	5 months	3/31/16
Subtotal	15,700	650	16,350		
TFX Seasonal (November - March)	2,000	0	2,000	5 years	10/31/19
TFX (Annual)	13,000	0	13,000	11.5 years	3/31/24
BP Seasonal Contract	730	(730)	0	5 months	3/31/16
Heating Season Total Capacity:	15,700	650	16,350		
Non-Heating Season Total Capacity:	8,000	0	8,000		
Forecasted Heating Season Design Day:	15,409	147	15,556		
Estimated Non-Heating Season Design Day:	8,741	60	8,801		
Heating Season Capacity: Surplus/(Shortage)	291	503	794		
Non-Heating Season Capacity: Surplus/(Shortage)	(741)	(60)	(801)		
Demand Profile for South District (dk):					
TF12 Base (Summer & Winter)	4,604	0	4,604	5 years	10/31/19
TF12 Variable (Summer & Winter)	2,931	0	2,931	5 years	10/31/19
TF5 (November - March)	3,410	0	3,410	5 years	10/31/19
TFX Negotiated (November - March)	1,000	0	1,000	10.5 years	3/31/25
TFX Seasonal (November - March)	5,200	0	5,200	5 years	10/31/19
TFX (Annual)	2,000	0	2,000	10 years	10/31/25
Proposed: TFX Seasonal - Capacity Release	0	(1,300)	(1,300)	5 months	3/31/17
TFX Seasonal - Capacity Release	(1,300)	1,300	0	5 months	3/31/16
Subtotal	17,845	0	17,845		
FT-A - Zone 1-1 (April - October)	5,000	0	5,000	1 year	10/31/17
FDD-1 Reservation	4,640	0	4,640	5 years	5/31/20
Heating Season Total Capacity:	17,845	0	17,845		
Non-Heating Season Total Capacity:	14,535	0	14,535		
Forecasted Heating Season Design Day:	16,858	(16)	16,842		
Estimated Non-Heating Season Design Day:	9,036	(6)	9,030		
Heating Season Capacity: Surplus/(Shortage)	987	16	1,003		
Non-Heating Season Capacity: Surplus/(Shortage)	5,499	6	5,505		

1/ Minnesota North District communities plus Wahpeton, ND.

GREAT PLAINS NATURAL GAS CO.
DEMAND PROFILE
NORTH DISTRICT

2014-2015 Heating Season	
G004/M-14-563	Quantity (dk)
FT-A (12 months)	8,000
FT-A (November through March)	5,000
BP Seasonal (Firm Gas to TBS)	500
TFX (November through March)	2,000
TFX (12 months)	13,000
FT-A (November through March)	2,000
Heating Season Total Capacity	15,500
Non-Heating Season Total Capacity	8,000
Total Entitlement (Including Peak Shaving)	15,500
Total Annual Transportation	8,000
Total Season Transportation	7,000
Total Percent Seasonal	45.16%

2015-2016 Heating Season	
G004/M-15-645	Quantity (dk)
FT-A (12 months)	8,000
FT-A (November through March)	5,700
BP Seasonal (Firm Gas to TBS)	-
TFX (November through March)	2,000
TFX (12 months)	13,000
FT-A (November through March)	2,000
BP Seasonal (Firm Gas to Chisago) 1/	730
Heating Season Total Capacity	15,700
Non-Heating Season Total Capacity	8,000
Total Entitlement	15,700
Total Annual Transportation	8,000
Total Season Transportation	7,700
Total Percent Seasonal	49.04%

2016-2017 Heating Season		
G004/M-16-_____	Quantity (dk)	Difference
FT-A (12 months)	8,000	0
FT-A (November through March)	5,000	(700)
BP Seasonal (Firm Gas to TBS)	-	0
TFX (November through March)	2,000	0
TFX (12 months)	13,000	0
FT-A (November through March)	2,000	0
BP Seasonal (Firm Gas to Chisago) 1/	-	0
Proposed incremental capacity	1,350	1,350
Heating Season Total Capacity	16,350	650
Non-Heating Season Total Capacity	8,000	0
Total Entitlement	16,350	650
Total Annual Transportation	8,000	0
Total Season Transportation	7,000	(700)
Total Percent Seasonal	42.81%	-6.23%

1/ Does not impact demand profile.

GREAT PLAINS NATURAL GAS CO.
DEMAND PROFILE
SOUTH DISTRICT

2014-2015 Heating Season G004/M-14-563	Quantity (dk)	2015-2016 Heating Season G004/M-15-645	Quantity (dk)	2016-2017 Heating Season G004/M-16-_____	Quantity (dk)	Difference
TF-12 Base	5,100	TF-12 Base	4,604	TF-12 Base	4,604	0
TF-12 Variable	2,435	TF-12 Variable	2,931	TF-12 Variable	2,931	0
FT-A (April through October)	5,000	FT-A (April through October)	5,000	FT-A (April through October)	5,000	0
TF-5 (November through March)	3,410	TF-5 (November through March)	3,410	TF-5 (November through March)	3,410	0
TFX (November through March)	6,200	TFX (November through March)	6,200	TFX (November through March)	6,200	0
		TFX (Annual)	2,000	TFX (Annual)	2,000	0
		TFX - Capacity Release	(1,300)	TFX - Capacity Release	(1,300)	0
FDD-1 Reservation	4,640	FDD-1 Reservation	4,640	FDD-1 Reservation	4,640	0
Heating Season Total Capacity	17,145	Heating Season Total Capacity	17,845	Heating Season Total Capacity	17,845	0
Non-Heating Season Total Capacity	12,535	Non-Heating Season Total Capacity	14,535	Non-Heating Season Total Capacity	14,535	0
Total Entitlement (Including Peak Shaving)	17,145	Total Entitlement	17,845	Total Entitlement	17,845	0
Total Annual Transportation	7,535	Total Annual Transportation	9,535	Total Annual Transportation	9,535	0
Total Season Transportation	9,610	Total Season Transportation	10,310	Total Season Transportation	10,310	0
Percent TF-5	31.16%	Percent TF-5	31.16%	Percent TF-5	31.16%	0.00%
Total Percent Seasonal	56.05%	Total Percent Seasonal	57.78%	Total Percent Seasonal	57.78%	0.00%

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2016 - 2017 HEATING SEASON
DESIGN DAY - NOVEMBER 2016

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	0.03961	0.01374	0.97169	96	2,501	2,530	1.35865	3,438	24	3,462		
North 4	0.05577	0.01330	0.96137	91	7,075	7,127	1.26607	9,020	63	9,083		
Wahpeton	0.07470	0.01413	0.98257	91	2,170	2,197	1.36053	2,990	21	3,011		
Total North District					11,746	11,854		15,448	108	15,556	16,350	5.1%
South 13	0.05233	0.01622	0.97828	83	11,884	11,959	1.39859	16,725	117	16,842	17,845	6.0%
Total					23,630	23,813		32,173	225	32,398	34,195	5.5%

1/ Use per customer factors based on regression analysis for the 36 months ending March 2016.
2/ Design Heating Degree Days Base 60 degrees F.
3/ Reflects monthly average for December 2015 - February 2016.
4/ Customer growth is based on regression analysis for the 36 months ending March 2016 with composite growth rates of: Crookston = 1.30%, North = 0.85%, Wahpeton = 1.21%, South = 0.70%.
5/ Lost and Unaccounted for Gas percentage of 0.7%.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2016
NORTH DISTRICT

	Last Rate Case 1/	Last Demand Change 2/	Current Rates 3/	Proposed 4/	% Change from Last Rate Case	% Change from Last Demand Change	% Change from Current Rates	Change from Current Rates
Residential								
Commodity Cost of Gas	$3.1328	$2.4418	$1.9588	$1.9588	-37.5%	-19.8%	0.0%	$0.0000
Demand Cost of Gas	1.5215	1.6118	1.6503	1.6352	7.5%	1.5%	-0.9%	(0.0151)
Commodity Margin 5/	1.7207	1.7207	1.7207	1.7207	0.0%	0.0%	0.0%	0.0000
Total Rate	6.3750	5.7743	5.3298	5.3147	-16.6%	-8.0%	-0.3%	(0.0151)
Average Annual Usage (dk)	103.8	103.8	103.8	103.8				
Average Annual Cost of Gas	$661.73	$599.37	$553.23	$551.67	-16.6%	-8.0%	-0.3%	($1.56)
Firm General Service								
Commodity Cost of Gas	$3.1328	$2.4418	$1.9588	$1.9588	-37.5%	-19.8%	0.0%	$0.0000
Demand Cost of Gas	1.5215	1.6118	1.6503	1.6352	7.5%	1.5%	-0.9%	(0.0151)
Commodity Margin 5/	1.4071	1.4071	1.4071	1.4071	0.0%	0.0%	0.0%	0.0000
Total Rate	6.0614	5.4607	5.0162	5.0011	-17.5%	-8.4%	-0.3%	(0.0151)
Average Annual Usage (dk)	375.7	375.7	375.7	375.7				
Average Annual Cost of Gas	$2,277.27	$2,051.58	$1,884.59	$1,878.91	-17.5%	-8.4%	-0.3%	($5.68)

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%	($0.0151)	-0.9%	($0.0151)	-0.3%	($1.56)
Firm General Service	0.0000	0.0%	(0.0151)	-0.9%	(0.0151)	-0.3%	($5.68)

1/ Base Cost of Gas Effective January 1, 2016 in Docket No. G004/MR-15-878.
2/ Demand in Docket No. G004/AA-15-951, effective November 1, 2015.
3/ Most recently filed PGA: June 2016.
4/ Proposed in this docket, G004/M-16-____ effective November 1, 2016.
5/ Includes CCRA and GAP.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2016
SOUTH DISTRICT

	Last Rate Case 1/	Last Demand Change 2/	Current Rates 3/	Proposed 4/	% Change from Last Rate Case	% Change from Last Demand Change	% Change from Current Rates	Change from Current Rates
Residential								
Commodity Cost of Gas	$3.2123	$2.5794	$2.0658	$2.0658	-35.7%	-19.9%	0.0%	$0.0000
Demand Cost of Gas	1.2379	1.3854	1.2324	1.2324	-0.4%	-11.0%	0.0%	0.0000
Commodity Margin 5/	1.3367	1.3367	1.3367	1.3367	0.0%	0.0%	0.0%	0.0000
Total Rate	5.7869	5.3015	4.6349	4.6349	-19.9%	-12.6%	0.0%	0.0000
Average Annual Usage (dk)	88.2	88.2	88.2	88.2				
Average Annual Cost of Gas	$510.40	$467.59	$408.80	$408.80	-19.9%	-12.6%	0.0%	$0.00
Firm General Service								
Commodity Cost of Gas	$3.2123	$2.5794	$2.0658	$2.0658	-35.7%	-19.9%	0.0%	$0.0000
Demand Cost of Gas	1.2379	1.3854	1.2324	1.2324	-0.4%	-11.0%	0.0%	0.0000
Commodity Margin 5/	1.0889	1.0889	1.0889	1.0889	0.0%	0.0%	0.0%	0.0000
Total Rate	5.5391	5.0537	4.3871	4.3871	-20.8%	-13.2%	0.0%	0.0000
Average Annual Usage (dk)	340.9	340.9	340.9	340.9				
Average Annual Cost of Gas	$1,888.28	$1,722.81	$1,495.56	$1,495.56	-20.8%	-13.2%	0.0%	$0.00

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%	$0.0000	0.0%	$0.0000	0.0%	$0.00
Firm General Service	0.0000	0.0%	0.0000	0.0%	0.0000	0.0%	$0.00

1/ Base Cost of Gas Effective January 1, 2016 in Docket No. G004/MR-15-878.
2/ Demand in Docket No. G004/AA-15-1011, effective December 1, 2015.
3/ Most recently filed PGA: May 2016.
4/ Proposed in this docket, G004/M-16-____ effective November 1, 2016.
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)
2016-2017	11,854	11	0.09%	15,556	147	0.95%	16,350	650	4.14%	5.10%
2015-2016	11,843	161	1.38%	15,409	597	4.03%	15,700	200	1.29%	1.89%
2014-2015	11,682	103	0.89%	14,812	672	4.75%	15,500	500	3.33%	4.64%
2013-2014	11,579	172	1.51%	14,140	(104)	-0.73%	15,000	0	0.00%	6.08%
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			2.40%			1.96%			2.91%	6.58%

	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)
2016-2017				0.0670	1.3123	1.3793	
2015-2016	11,664	(2,204)	-15.89%	0.0246	1.3011	1.3257	0.9849
2014-2015	13,868	632	4.77%	0.0589	1.2679	1.3268	1.1871
2013-2014	13,236	1,530	13.07%	0.0743	1.2212	1.2954	1.1431
2012-2013	11,706	3,265	38.68%	0.0663	1.2487	1.3150	1.0262
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			1.49%	0.0941	1.4322	1.5262	1.1405

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)
2016-2017	11,959	(80)	-0.66%	16,842	(16)	-0.09%	17,845	0	0.00%	5.96%
2015-2016	12,039	197	1.66%	16,858	546	3.35%	17,845	700	4.08%	5.85%
2014-2015	11,842	193	1.66%	16,312	1,019	6.66%	17,145	1,500	9.59%	5.11%
2013-2014	11,649	118	1.02%	15,293	443	2.98%	15,645	0	0.00%	2.30%
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			0.55%			-0.15%			0.36%	5.62%

	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)
2016-2017				0.0839	1.4083	1.4922	
2015-2016	15,582	351	2.30%	0.0820	1.4003	1.4823	1.2943
2014-2015	15,231	774	5.35%	0.0703	1.3775	1.4478	1.2862
2013-2014	14,457	1,941	15.51%	0.0302	1.3128	1.3430	1.2411
2012-2013	12,516	2,248	21.89%	0.0689	1.2878	1.3568	1.0854
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			0.25%	0.0797	1.4573	1.5370	1.2245