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

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1-877-267-4764

June 30, 2017

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-17-___

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 2017-2018 winter heating season.

Great Plains received Commission approval to consolidate the North and South Purchased Gas Cost (PGA) Districts, effective July 1, 2017 in Docket No. G004/MR-15-879. The analysis provided in this Demand Entitlement Filing (DEQ) is based on one consolidated PGA district.

Great Plains is requesting an increase in capacity of 1,100 Dk per day on Viking Gas Transmission (VGT) as shown on Exhibit B. Great Plains requests the additional capacity be effective November 1, 2017.

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

Exhibit A – Design Day Capacity Requirements
Exhibit B – Capacity Portfolio
Exhibit C – Rate Impacts
Exhibit D – Demand Entitlement Analysis
Exhibit E – Autocorrelation Discussion

Design Day Capacity Requirements

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 Marshall, Crookston, and Fergus Falls, Minnesota, along with Wahpeton, North Dakota. The calculations are consistent with the design day methodologies accepted by the Commission in previous Dockets[1].

As shown on Exhibit A, Great Plains has calculated a projected design day requirement of 32,733 Dk/day. This projection consists of 15,821 Dk/day for firm customers receiving natural gas from city gates interconnecting with VGT and 16,912 Dk/day for those firm customers receiving natural gas from city gates interconnecting with Northern Natural Gas (NNG).

Great Plains has a long history of successfully serving its customers gas requirements in a safe, reliable and economical fashion. While Great Plains' regression models may exhibit evidence of autocorrelation, the Company believes its regressions are accurate, can be relied upon for forecasting demand requirements, and the resulting design day peak capacity requirements are not unreasonable. Great Plains serves approximately 24,000 customers and is intimately familiar with its customer's gas usage, conservation and growth characteristics. Further discussion regarding the autocorrelation present in the regression models is provided in Exhibit E.

Capacity Portfolio

Current

Transmission capacity currently subscribed to and effective November 1, 2017 totals 49,145 Dk/day. Within this value, 34,145 Dk/day directly interconnects to Great Plains' city gates. The remaining 15,000 Dk/day has been contracted such that natural gas may be purchased from markets located on upstream transmission pipelines that do not interconnect with Great Plains' city gates. This is referred to as supplemental capacity.

Currently subscribed transmission capacity that directly interconnects with Great Plains' city gates includes 15,000 Dk/day on VGT to serve the city gates of Crookston, MN and communities located on Great Plains' transmission lateral located between Vergas, MN and Wahpeton, ND. These consist of 13,000 Dk/day of annual capacity and 2,000 Dk/day of seasonal (Nov-Mar) capacity.

As noted in the October 31, 2016 update submitted in Docket No. G004/M-16-557, Great Plains procured 1,400 Dk/day of seasonal capacity on VGT for the 2016-2017 heating season. This contract has expired.

[1] Docket No. G004/M-13-566: Order dated January 9, 2014, Docket No. G004/M-14-563: Order dated August 11, 2015, Docket No. G004/M-15-645: Order dated June 8, 2017 and Docket No. G004/M-16-557: Order dated June 8, 2017.

The currently held VGT capacity is sourced by 15,000 Dk/day of supplemental capacity on NNG's transmission system. The supplemental capacity on NNG consists of 13,000 Dk/day of annual capacity and 2,000 Dk/day of seasonal capacity, which matches the VGT subscribed capacity discussed above. Specifically, natural gas is purchased from market locations on NNG's transmission system (typically NNG-Ventura), transported to a NNG/VGT interconnect (Chisago), and subsequently transported to Great Plains' city gates interconnecting with VGT.

To provide transmission service to Great Plains' communities interconnecting with NNG, Great Plains holds contracts for a maximum delivery quantity (MDQ) of 19,145 Dk/day. Of this quantity, 9,535 Dk/day is under annual subscription while 9,610 Dk/day is under seasonal (Nov-Mar) subscription. This capacity directly connects three market locations to all Great Plains' city gates interconnecting with NNG's transmission system. The capacity on NNG includes the 10-year contract for 2,000 Dk/day of annual capacity approved by Commission Order in Docket Nos. G-004/M-15-645 and G-004/M-16-557 on June 8, 2017.

During the 2016-2017 heating season, Great Plains released 1,300 Dk/day of NNG capacity and the terms of those releases have expired. Great Plains intends to use the 1,300 Dk/day, previously released, for purposes of serving VGT city gates, on a supplemental capacity basis, as described in the *Proposed* section below.

Based on approved methodologies for calculating design day capacity requirements and Great Plains' current capacity levels, Great Plains is anticipating a consolidated reserve margin of 4.3 percent. Based on the Commission's direction of maintaining reserve margins of approximately 5 percent [2], Great Plains shall seek additional capacity to ensure the deliverability of natural gas to its firm customers.

Proposed

VGT is currently holding an open-season for capacity that has recently become available on their system and customers may bid to secure contracts for incremental transmission capacity. Great Plains proposes to place a bid for up to 2,500 Dk/day of incremental capacity through this open season, as shown on Exhibit B, Page 1. This 2,500 Dk/day of incremental capacity will consist of 1,600 Dk/day to replace the 1,400 Dk/day which expired after the 2016-2017 heating season. The remaining 900 Dk/day of capacity is to be utilized in future years, avoiding the potential need to fund a VGT transmission expansion project.

If awarded, Great Plains will have the opportunity to utilize 1,300 Dk/day of currently contracted NNG capacity, previously contracted for future use for NNG city gate delivery, as supplemental capacity to provide delivery from NNG market locations to the NNG/VGT interconnect (Chisago.) The newly contracted capacity will take delivery of this natural gas to VGT interconnected city gates.

[2] Ordering Paragraph No. 4 of the Commission's September 30, 2010 Order in Docket Nos. G004/M-07-1401, G004/M-08-1306 and G004/M-09-1262.

Great Plains proposes this arrangement as supplying VGT city gates from NNG market locations provides a robust and reliable source of natural gas for its customers. Also, Great Plains has considered VGT's sporadic availability of capacity and finds it appropriate to seek delivery quantities greater than required for the 2017-2018 heating season in anticipation that capacity may not be available in future years. The proposed portfolio also more equitably and evenly distributes capacity such that city gates interconnecting with either available transmission company have appropriate levels of transmission capacity.

As shown on Exhibit A, these actions will yield a consolidated reserve margin of 8.0 percent for Great Plains' customers. Furthermore, these actions will provide for a projected reserve margin of at least 5.5 percent through the 2019-2020 heating season. 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.

If Great Plains is unsuccessful in its bid to secure additional VGT capacity, the option to purchase a delivered supply of natural gas at either of the VGT city gates will be available on a term or spot basis.

Exhibit B, page 2, shows the consolidated demand profile history for the 2015-2016, 2016-2017 and the proposed 2017-2018 heating seasons.

Rate Impacts

Table 1: Proposed Demand Costs

Interstate Pipelines	Volumes (1) Dk/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. 3)	5,000	4.3706	12	262,236
FT-A Seasonal (Cat. 3)	2,000	4.3706	5	43,706
Proposed: FT-A - Zone 1-1 (Cat. 3)	2,500	4.3706	12	131,118
NNG				
TFX - Summer	13,000	5.6830	7	517,153
TFX - Winter	13,000	15.1530	5	984,945
TFX Seasonal (Nov. - Mar.)	2,000	15.1530	5	151,530
TF12 Base - Summer	5,421	5.6830	7	215,653
TF12 Base - Winter	5,421	10.2300	5	277,284
TF12 Variable - Summer	2,114	5.6830	7	84,097
TF12 Variable - Winter	2,114	13.8660	5	146,564
TF5	3,410	15.1530	5	258,359
TFX - Winter	5,200	15.1530	5	393,978
TFX - Annual (Summer Rate)	2,000	5.6830	7	79,562
TFX - Annual (Winter Rate)	2,000	15.1530	5	151,530
TFX Negotiated Contract	1,000	26.8918	5	134,459
FDD-1 Reservation	4,640	1.7140	12	95,436
Interruptible Demand Credit				(346,292)
Total Demand Charges				$4,000,896

Pursuant to NNG's FERC tariff, NNG adjusts the MDQ associated with the TF12 Base and TF12 Variable effective November 1 of each year, based on the amount of capacity used during the preceding May – September period. Currently, the adjustment is pending; however, the change is typically insignificant. The change in the TF12 Base and TF12 Variable will be available by November 1, 2017 and Great Plains will provide a report to the Commission regarding the amount of the TF12 Base and TF12 Variable in place for the 2017-2018 heating season at that time.

Great Plains was requested to address the NNG TFX Negotiated contract rate of $26.8918 for 1,000 Dk/day from November through March, expiring on March 31, 2025. This contract provided necessary capacity for firm customers located behind city gates interconnecting with NNG. For the 2014-2015 heating season, Great Plains required additional capacity to meet demand requirements for the South District. NNG was fully subscribed at that time, and the least costly option available was to subscribe for capacity made available after enhancements to NNG's system. The rate includes NNG's cost recovery for those specific enhancements.

Exhibit C shows the impacts to customers due to the capacity changes discussed above. This Exhibit is shown as North and South Districts. Certain components have not yet been consolidated, such as the annual GCR rates, which will be consolidated on, or before, September 1, 2017, and the Commodity Margin, which will be consolidated on January 1, 2019.

There is an increase of 2.7 percent in the demand component cost for firm customers based on the proposed capacity levels and current pricing from the rates in effect in July 2017. The estimated rate impacts include the successful acquisition of the 2,500 Dk/day of incremental capacity as proposed above.

The total customer impact of the updated demand profile compared to rates effective July 2017 is an increase of $0.0346 per dk. Please see Table 2 below for the annual rate impacts reflecting the capacity and prices noted in Table 1 above.

Table 2: Proposed Demand Cost Impacts

Filing Date	Residential Customer (77.9 Dk)	Total Change Res (%)	Firm General Service (434.4 Dk)	Total Change FGS (%)
June 30, 2017	$2.70	2.7	$15.03	2.7

<u>Demand Entitlement Analysis</u>

Exhibit D reflects the up-coming 2017-2018 heating season, on a consolidated basis, for the design day requirement, total entitlement and peak day design, entitlement and firm sendout per customer.

The North and South Districts' 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 have been included for reference.

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

Exhibit A

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2017 - 2018 HEATING SEASON
DESIGN DAY - NOVEMBER 2017

Pipeline	Customer Factors 1/ Dk/day	Dk/DD	RSqr	Design HDD 2/	No. of Customers 3/	Projected Customers 4/	Peak/ Customer	Projected Peak Day (dk)	L&UA 5/	Projected Design	Proposed Capacity	Reserve
VGT												
Crookston	0.04204	0.01409	0.98198	96	2,524	2,554	1.39468	3,561	25	3,586		
North 4	0.05467	0.01332	0.95988	91	7,145	7,191	1.26679	9,106	64	9,170		
Wahpeton	0.07393	0.01417	0.98646	91	2,195	2,231	1.36340	3,044	21	3,065		
Total VGT					11,864	11,976		15,711	110	15,821		
NNG	0.05342	0.01619	0.98566	83	11,946	12,021	1.39719	16,794	118	16,912		
Total					23,810	23,997		32,505	228	32,733	35,345	8.0%

1/ Use per customer factors based on regression analysis for the 36 months ending March 2017.
2/ Design Heating Degree Days Base 60 degrees F.
3/ Reflects monthly average for December 2016 - February 2017.
4/ Customer growth is based on regression analysis for the 36 months ending March 2017 with composite growth rates of: Crookston = 1.32%, North = 0.87%, Wahpeton = 1.13%, South = 0.63%.
5/ Lost and Unaccounted for Gas percentage of 0.7%.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2017 - 2018 HEATING SEASON
DEMAND PROFILE EFFECTIVE NOVEMBER 1, 2017

Type of Capacity or Entitlement	Authorized Amount	Proposed Change		Proposed Amount	Contract Length	Expiration Date
Demand Profile (dk) 1/						
VGT						
FT-A - Zone 1-1 (Cat. 3)	8,000	0		8,000	5 years	10/31/22
FT-A - Zone 1-1 (Cat. 3)	5,000	0		5,000	1 year	10/31/22
FT-A (Cat. 3) Seasonal (November - March)	2,000	0		2,000	1 year	10/31/22
FT-A (November - March)	1,400	(1,400)		0	5 months	3/31/17
Proposed: FT-A - Zone 1-1 (Cat. 3)	0	2,500		2,500	5 years	10/31/22
NNG						
TF12 Base (Summer & Winter)	5,421	0		5,421	5 years	10/31/19
TF12 Variable (Summer & Winter)	2,114	0		2,114	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	(1,300)	2/	700	10 years	10/31/25
TFX Seasonal - Capacity Release	(1,000)	1,000		0	5 months	3/31/17
TF12 - Capacity Release	(300)	300		0	4 months	3/31/17
Subtotal	34,245	1,100		35,345		
Supplemental Capacity						
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
TFX (Annual)	0	1,300	2/	1,300	10 years	10/31/25
Storage						
FDD-1 Reservation	4,640	0		4,640	5 years	5/31/20
Heating Season Total Capacity:	34,245	1,100		35,345		
Non-Heating Season Total Capacity:	22,535	0		22,535		
Forecasted Heating Season Design Day:	32,398	335		32,733		
Estimated Non-Heating Season Design Day:	17,831	195		18,026		
Heating Season Capacity: Surplus/(Shortage)	1,847	765		2,612		
Non-Heating Season Capacity: Surplus/(Shortage)	4,704	(195)		4,509		

1/ Minnesota communities plus Wahpeton, ND.
2/ Northern Natural capacity to be used as supplemental capacity to deliver gas to Viking at Chisago for "back-haul" transport to Vergas, MN.

GREAT PLAINS NATURAL GAS CO.
DEMAND PROFILE

2015-2016 Heating Season G004/M-15-645	Quantity (dk)	2016-2017 Heating Season G004/M-16-557	Quantity (dk)	2017-2018 Heating Season G004/M-17-___	Quantity (dk)	Difference
FT-A (Cat. 3) (12 months)	8,000	FT-A (Cat. 3) (12 months)	8,000	FT-A (Cat. 3) (12 months)	8,000	0
FT-A (Cat. 1) (12 months)	5,000	FT-A (Cat. 1) (12 months)	5,000	FT-A (Cat. 3) (12 months)	5,000	0
FT-A (November - March)	2,000	FT-A (November - March)	2,000	FT-A (Cat. 3) (November - March)	2,000	0
BP Seasonal (Firm Gas to Chisago) 1/	730	BP Seasonal (Firm Gas to Chisago)	-	BP Seasonal (Firm Gas to Chisago)	-	0
FT-A (November - March)	700	FT-A (November - March)	1,400	FT-A (November - March)	-	(1,400)
				FT-A (Cat. 3) (12 months)	2,500	2,500
TFX (12 months)	13,000	TFX (12 months)	13,000	TFX (12 months)	13,000	0
TFX (November - March)	2,000	TFX (November - March)	2,000	TFX (November - March)	2,000	0
TF-12 Base	4,604	TF-12 Base	5,421	TF-12 Base	5,421	0
TF-12 Variable	2,931	TF-12 Variable	2,114	TF-12 Variable	2,114	0
TF-5 (November- March)	3,410	TF-5 (November- March)	3,410	TF-5 (November- March)	3,410	0
TFX (November - March)	5,200	TFX (November - March)	5,200	TFX (November - March)	5,200	0
TFX - Negotiated (November - March)	1,000	TFX - Negotiated (November - March)	1,000	TFX - Negotiated (November - March)	1,000	0
TFX (Annual)	2,000	TFX (Annual)	2,000	TFX (Annual) 2/	2,000	0
TFX - Capacity Release	(1,300)	TFX - Capacity Release	(1,000)	TFX - Capacity Release	-	1,000
		TF-12 - Capacity Release	(300)	TF-12 - Capacity Release	-	300
FDD-1 Reservation	4,640	FDD-1 Reservation	4,640	FDD-1 Reservation	4,640	0
Heating Season Total Capacity	33,545	Heating Season Total Capacity	34,245	Heating Season Total Capacity 3/	35,345	1,100
Non-Heating Season Total Capacity	22,535	Non-Heating Season Total Capacity	22,535	Non-Heating Season Total Capacity	22,535	0
Total Entitlement (Including Peak Shaving)	33,545	Total Entitlement	34,245	Total Entitlement 3/	35,345	1,100
Total Annual Transportation	22,535	Total Annual Transportation	22,535	Total Annual Transportation 3/	23,735	1,200
Total Season Transportation	11,010	Total Season Transportation	11,710	Total Season Transportation	11,610	(100)
Percent TF-5	31.16%	Percent TF-5	31.16%	Percent TF-5	31.16%	0.00%
Total Percent Seasonal	32.82%	Total Percent Seasonal	34.19%	Total Percent Seasonal	32.85%	-1.34%

1/ Does not impact demand profile.
2/ Demand profile includes 700 dk: Remaining 1,300 dk used to deliver gas to Viking interconnect at Chisago for 1,300 dk FT-A (12 Months) "back-haul" contract to Vergas, MN.
3/ Includes 700 dk of total 2,000 dk from TFX (Annual) contract for capacity and demand profile calculation.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2017
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 5/	$2.60630	$2.94760	$2.95690	$2.95690	13.5%	0.3%	0.0%	$0.00000
Demand Cost of Gas	1.18900	1.63600	1.26110	1.29570	9.0%	-20.8%	2.7%	0.03460
Commodity Margin 6/	2.25960	2.02620	2.27353	2.27353	0.6%	12.2%	0.0%	0.00000
Total Rate	$6.05490	$6.60980	$6.49153	$6.52613	7.8%	-1.3%	0.5%	$0.03460
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$471.68	$514.90	$505.69	$508.39	7.8%	-1.3%	0.5%	$2.70
Firm General Service								
Commodity Cost of Gas 5/	$2.60630	$2.94760	$2.95690	$2.95690	13.5%	0.3%	0.0%	$0.00000
Demand Cost of Gas	1.18900	1.63600	1.26110	1.29570	9.0%	-20.8%	2.7%	0.03460
Commodity Margin 6/	1.84870	1.65710	1.86263	1.86263	0.8%	12.4%	0.0%	0.00000
Total Rate	$5.64400	$6.24070	$6.08063	$6.11523	8.3%	-2.0%	0.6%	$0.03460
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,451.75	$2,710.96	$2,641.43	$2,656.46	8.3%	-2.0%	0.6%	$15.03

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%	$0.0346	2.7%	$0.0346	0.5%	$2.70
Firm General Service	0.0000	0.0%	0.0346	2.7%	0.0346	0.6%	$15.03

1/ Consolidated Base Cost of Gas effective July 1, 2017 in update to Docket No. G004/MR-16-834. Commodity margin effective January 1, 2017 in Docket No. G004/GR-15-879.
2/ Demand in Docket No. G004/AA-16-885, effective November 1, 2016: Commodity Margin includes interim adjustment of 17.671% effective January 1, 2016 - Docket No. G004/GR-15-879.
3/ Most recently filed PGA: July 2017.
4/ Consolidated commodity and demand costs proposed in this docket, G004/M-17-___ effective November 1, 2017.
5/ Includes GCR rate of $0.0762 (effective September 1, 2016 - Docket No. G004/AA-16-719).
6/ Includes CCRA of $0.2125 (effective January 1, 2017 - Docket No. G004/M-16-384) and GAP of $0.01393 (effective June 1, 2017 - Docket No. G004/M-16-495).

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2017
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 5/	$2.69280	$3.04810	$3.04340	$3.04340	13.0%	-0.2%	0.0%	$0.00000
Demand Cost of Gas	1.18900	1.23410	1.26110	1.29570	9.0%	5.0%	2.7%	0.03460
Commodity Margin 6/	1.75920	1.57430	1.77313	1.77313	0.8%	12.6%	0.0%	0.00000
Total Rate	$5.64100	$5.85650	$6.07763	$6.11223	8.4%	4.4%	0.6%	$0.03460
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$439.43	$456.22	$473.45	$476.14	8.4%	4.4%	0.6%	$2.69
Firm General Service								
Commodity Cost of Gas 5/	$2.69280	$3.04810	$3.04340	$3.04340	13.0%	-0.2%	0.0%	$0.00000
Demand Cost of Gas	1.18900	1.23410	1.26110	1.29570	9.0%	5.0%	2.7%	0.03460
Commodity Margin 6/	1.47070	1.28270	1.48463	1.48463	0.9%	15.7%	0.0%	0.00000
Total Rate	$5.35250	$5.56490	$5.78913	$5.82373	8.8%	4.7%	0.6%	$0.03460
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,325.13	$2,417.39	$2,514.80	$2,529.83	8.8%	4.7%	0.6%	$15.03

	Commodity Change		Demand Change		Total Change		Average Annual
Customer Class	($/dk)	(Percent)	($/dk)	(Percent)	($/dk)	(Percent)	Bill Change
Residential	$0.0000	0.0%	$0.0346	2.7%	$0.0346	0.6%	$2.69
Firm General Service	0.0000	0.0%	0.0346	2.7%	0.0346	0.6%	$15.03

1/ Consolidated Base Cost of Gas effective July 1, 2017 in update to Docket No. G004/MR-16-834. Commodity margin effective January 1, 2017 in Docket No. G004/GR-15-879.
2/ Demand in Docket No. G004/AA-16-885, effective November 1, 2016: Commodity Margin includes interim adjustment of 17.671% effective January 1, 2016 - Docket No. G004/GR-15-879.
3/ Most recently filed PGA: July 2017.
4/ Consolidated commodity and demand costs proposed in this docket, G004/M-17-___ effective November 1, 2017.
5/ Includes GCR rate of $0.1627 (effective September 1, 2016 - Docket No. G004/AA-16-719).
6/ Includes CCRA of $0.2125 (effective January 1, 2017 - Docket No. G004/M-16-384) and GAP of $0.01393 (effective June 1, 2017 - Docket No. G004/M-16-495).

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT ANALYSIS

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Storage + Peak Shaving			
Heating Season	(1) Number of Customers	(2) Change From Previous Year	(3) % Change From Previous Year	(4) Design Day (dk)	(5) Change From Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (dk)	(8) Change From Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2017-2018	23,997			32,733			35,345			8.0%
Annual Average			0.00%			0.00%			0.00%	8.0%

	Firm Peak Day Sendout						
Heating Season	(11) Firm Peak Day Sendout (dk)	(12) Change From Previous Year	(13) % Change From Previous Year	(14) Excess Per Customer [(7)-(4)]/(1)	(15) Design Day per Customer (4)/(1)	(16) Entitlement per Customer (7)/(1)	(17) Peak Day Sendout per Customer (11)/(1)
2017-2018	0			0.1088	1.3640	1.4729	0.0000
Annual Average			0.00%	0.1088	1.3640	1.4729	0.0000

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%	16,400	700	4.46%	5.43%
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%			2.93%	6.60%

	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	13,328	1,664	14.27%	0.0712	1.3123	1.3835	1.1243
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			2.09%	0.0943	1.4322	1.5264	1.1398

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			
Heating Season	(1) Number of Customers	(2) Change From Previous Year	(3) % Change From Previous Year	(4) Design Day (dk)	(5) Change From Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (dk)	(8) Change From Previous Year	(9) % Change From Previous Year	(10) % 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						
Heating Season	(11) Firm Peak Day Sendout (dk)	(12) Change From Previous Year	(13) % Change From Previous Year	(14) Excess Per Customer [(7)-(4)]/(1)	(15) Design Day per Customer (4)/(1)	(16) Entitlement per Customer (7)/(1)	(17) Peak Day Sendout per Customer (11)/(1)
2016-2017	15,201	(381)	-2.45%	0.0839	1.4083	1.4922	1.2711
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			0.12%	0.0797	1.4573	1.5370	1.2266

Autocorrelation in Regression Models

In accordance with the Commission's Order in Docket No. G-004/M-16-557, Great Plains submits the following information with regard to autocorrelation in the statistical models used to estimate its peak day requirements for the annual Demand Entitlement filing.

Great Plains utilizes an ordinary least squares (OLS) regression model to normalize volumes for each rate class. Volume normalization is a method in which temperature activity is accounted for when looking at historical natural gas usage. A primary concern raised when developing an OLS model that is based on a set of time series data is serial correlated error terms, or autocorrelation. One of the key assumptions when creating a statistical model is randomness of data. If this assumption is broken or does not hold true, then the model itself is flawed and may cause unreliable parameters or estimators. The bias created from a faulty model can lead to further problems if these estimators are used to project future data. An OLS model is represented as follows:

$$y_i = \ a + \beta X_i + u_i$$

As such, u_i is all unobservable data, or errors, at time period *i* that can affect the model. One of the assumptions that is made for this model is that $E(u_i, u_j) = 0$. This assumption states that there is no covariance between error terms at times *i* and *j* in the model and *i* and *j* are independent from each other. However, time-series data sometimes exhibits a serial correlation between error terms which causes the OLS to no longer become the most appropriate model to utilize as one of the basic assumptions does not hold. This autocorrelation causes a misrepresentation of the estimators generated from the data that is used. Typically, the true variance (σ^2) of the population will be underestimated, t and F statistics will be inflated (which will cause the confidence intervals to decrease in size), and standard errors will be underestimated.

In Docket No. G-004/M-16-557, the Commission ordered Great Plains to check its regression models for autocorrelation and to correct if present. As such, Great Plains analyzed its regressions for autocorrelation utilizing the most recent 36 month data. Great Plains uses OLS regression models for residential and firm general customers separately for the North and South Districts. To determine the presence of autocorrelation for each respective District and class of customer, Durbin Watson test statistics were calculated using data sets in Microsoft Excel. Results show that there is sufficient evidence that autocorrelation is present for the following rates (with respective Durbin Watson statistics): North District Residential (1.29), and South District Residential (1.37). These rates were below the lower bound limit for the Durbin Watson test (1.41). The remaining firm general rates classes did not exhibit sufficient statistical evidence to suggest that autocorrelation was present.

The evidence that autocorrelation was present in the residential rate classes may suggest that the OLS models were no longer the best method of regression for the data presented. However, the Great Plains believes in maintaining the utilization of OLS regressions for these rate classes for various reasons. Although an alternative method to correct for autocorrelation would be to run an ARIMA (auto-regressive integrated moving average), it would be inappropriate to use a different statistical model for data sets whether they exhibited autocorrelation or not. An identical statistical method should be utilized for all rates; however, there are more rates that have evidence to support the absence of autocorrelation in their respective data sets so Great Plains believes that an OLS better fits the entirety of customer classes and should be the preferred statistical method rather than ARIMA. Great Plains also believes that any benefit that would come from purchasing statistical software for the sole purpose of correcting any autocorrelation issues would not exceed the coinciding cost. The inherent administrative burden that occurs with the purchase, training, and implementation of any statistical software would only be passed on to Great Plains' customers. Although such software could mitigate the autocorrelation errors in the regression models, Great Plains suggests that it is an unnecessary cost for either customers or the Company to bear.

As requested by the Commission, regression models and the underlying data have been analyzed for autocorrelation. While the presence of autocorrelation has been noted in select rate classes, Great Plains proposes that the current method of utilizing OLS regression models to normalize volumes is sufficient and the presence of autocorrelation does not significantly change the Company's proposed design-day requirement or the proposed level of demand entitlement in this filing. It is imperative that the Commission acknowledge the past approval of Great Plains regression models utilized in calculating a design-day requirement. In agreement with the Department, the Commission agreed to Great Plains regression methods in Docket No. G004/M-16-557, stating "the Company's design-day methodology was acceptable because its results were not unreasonable." Further, Great Plains believes its historical record shows the regression models provide a sufficient level of demand entitlements and the ability to meet customer demand in extreme weather circumstances. Again in Docket No. G004/M-16-557, the Department in its comments notes that even in light of extreme weather and an outage from a pipeline explosion, “the Company appears to have had sufficient levels of entitlements.” Great Plains considers the regression models used, and the values generated therein, are reasonable and just. Great Plains will continue to monitor its data and regression models for each rate class to monitor autocorrelation issues.