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

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Fergus Falls, MN 56538-0176
1-877-267-4764

June 29, 2018

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-18-___

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 2018-2019 winter heating season.

Great Plains is requesting an increase in capacity of 800 Dk per day on Viking Gas Transmission (VGT) as shown on Exhibit B. Great Plains requests the additional capacity be effective November 1, 2018.

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

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 individual regression analyses 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]. In addition, Great Plains monitored its data and regression models for the presence of autocorrelation and whether it has statistical significance to the projected design day requirement, as agreed to in Docket No. G004/M-17-521. While the results indicate autocorrelation is present, Great Plains does not have the means to determine the effect of autocorrelation on the design day requirement without purchasing additional software. Great Plains continues to support its current methodology, previously approved, as the modeling produces reasonable results.

As shown on Exhibit A, Great Plains has calculated a projected design day requirement of 33,674 Dk/day. This projection consists of 16,472 Dk/day for firm customers receiving natural gas from city gates interconnecting with VGT and 17,202 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. 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.

<u>Capacity Portfolio</u>

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 contracts consist of 13,000 Dk/day of annual capacity and 2,000 Dk/day of seasonal (Nov-Mar) capacity.

As noted in the November 1, 2017 update submitted in Docket No. G004/M-17-521, Great Plains entered into a contractual agreement with BP Canada Energy Marketing Corp. for a

[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, Docket No. G004/M-16-557: Order dated June 8, 2017 and Docket No. G004/M-17-521: Order dated May 15, 2018.

seasonal firm Capacity purchase of 1,600 Dk/day at a cost of $0.155 per Dk for the 2017-2018 heating season. This contract has expired.

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 currently 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.

During the 2017-2018 heating season, Great Plains utilized 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).

Proposed

Great Plains proposes to acquire 2,400 Dk/day of seasonal capacity from a third party on VGT, as shown on Exhibit B, Page 1. This 2,400 Dk/day of seasonal capacity is to replace the 1,600 Dk/day seasonal firm capacity purchase contract with BP Canada Energy Marketing Corp., which expired after the 2017-2018 heating season. If Great Plains is unsuccessful in its attempt to secure seasonal capacity on VGT, 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. The Company will update the Commission regarding the final seasonal capacity contract or delivered supply purchase by November 1, 2018.

Great Plains proposes to utilize 1,000 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). This is a reduction in amounts held as supplemental capacity of 300 Dk/day from the prior heating season, as demand continues to increase on city gate interconnects with NNG.

The arrangement of supplying VGT city gates from NNG market locations provides a robust and reliable source of natural gas for Great Plains' customers. The proposed portfolio 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 5.6 percent for Great Plains' customers. 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 changes in demand, as well as any effects of conservation.

Exhibit B, page 2, shows the consolidated demand profile history for the 2016-2017, 2017-2018 and the proposed 2018-2019 heating seasons.

Rate Impacts

Table 1: Proposed Demand Costs

Interstate Pipelines	Volumes Dk/day	Rates $	Months	Demand Costs $
VGT				
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: Seasonal Capacity (Cat. 1)	2,400	4.7507	5	57,008
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	4,854	5.6830	7	193,097
TF12 Base - Winter	4,854	10.2300	5	248,282
TF12 Variable - Summer	2,681	5.6830	7	106,653
TF12 Variable - Winter	2,681	13.8660	5	185,874
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				(339,304)
Total Demand Charges				$3,944,082

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, 2018 and Great Plains will provide a report to the Commission regarding the amount of the TF12 Base and TF12 Variable in place for the 2018-2019 heating season at that time.

Exhibit C shows the impacts to customers due to the capacity changes discussed above. There is an increase of 0.8 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 2018. The estimated rate impacts include the successful acquisition of the 2,400 Dk/day of seasonal capacity as proposed above.

The total customer impact of the updated demand profile compared to rates effective July 2018 is an increase of $0.0098 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 Residential (%)	Firm General Service (434.4 Dk)	Total Change FGS (%)
June 29, 2018	$0.76	0.8	$4.26	0.8

<u>Demand Entitlement Analysis</u>

Exhibit D reflects the up-coming 2018-2019 heating season, on a consolidated basis, for the design day requirement, total entitlement and peak day design, entitlement and firm sendout per customer.

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 2018 - 2019 HEATING SEASON
DESIGN DAY - NOVEMBER 2018

Pipeline	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	Proposed Capacity	Reserve
VGT												
Crookston	0.04628	0.01401	0.99619	96	2,542	2,563	1.39124	3,567	25	3,592		
North 4	0.05063	0.01404	0.99718	91	7,191	7,247	1.32827	9,626	67	9,693		
Wahpeton	0.07331	0.01422	0.96799	91	2,267	2,313	1.36733	3,165	22	3,187		
Total VGT					12,000	12,123		16,358	114	16,472		
NNG	0.05161	0.01636	0.99699	83	12,013	12,117	1.40949	17,082	120	17,202		
Total					24,013	24,240		33,440	234	33,674	35,545	5.6%

1/ Use per customer factors based on regression analysis for the 36 months ending March 2018.
2/ Design Heating Degree Days Base 60 degrees F.
3/ Reflects monthly average for December 2017 - February 2018.
4/ Customer growth is based on regression analysis for the 36 months ending March 2018 with composite growth rates of: Crookston = 0.83%, North = 0.78%, Wahpeton = 2.03%, South = 0.87%.
5/ Lost and Unaccounted for Gas percentage of 0.7%.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2018 - 2019 HEATING SEASON
DEMAND PROFILE EFFECTIVE NOVEMBER 1, 2018

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	5 years	10/31/22
FT-A Seasonal - Zone 1-1 (Cat. 3)	2,000	0	2,000	5 years	10/31/22
BP Contract (Firm Demand)	1,600	(1,600)	0	5 months	3/31/18
Proposed: Seasonal Capacity (Cat. 1)	0	2,400	2,400	5 months	3/31/19
NNG					
TF12 Base (Summer & Winter)	4,854	0	4,854	5 years	10/31/19
TF12 Variable (Summer & Winter)	2,681	0	2,681	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/	700	300	1,000	10 years	10/31/25
Subtotal	34,445	1,100	35,545		
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) 2/	1,300	(300)	1,000	10 years	10/31/25
Storage					
FDD-1 Reservation	4,640	0	4,640	5 years	5/31/20
Heating Season Total Capacity:	34,445	1,100	35,545		
Non-Heating Season Total Capacity:	22,535	0	22,535		
Forecasted Heating Season Design Day:	32,733	941	33,674		
Estimated Non-Heating Season Design Day:	18,026	481	18,507		
Heating Season Capacity: Surplus/(Shortage)	1,712	159	1,871		
Non-Heating Season Capacity: Surplus/(Shortage)	4,509	(481)	4,028		

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

2016-2017 Heating Season G004/M-16-557	Quantity (dk)
FT-A (Cat. 3) (12 months)	8,000
FT-A (Cat. 1) (12 months)	5,000
FT-A (November - March)	2,000
FT-A (November - March)	1,400
TFX (12 months) 1/	13,000
TFX (November - March) 1/	2,000
TF-12 Base	5,421
TF-12 Variable	2,114
TF-5 (November- March)	3,410
TFX (November - March)	5,200
TFX - Negotiated (November - March)	1,000
TFX (Annual)	2,000
TFX - Capacity Release	(1,000)
TF-12 - Capacity Release	(300)
FDD-1 Reservation 1/	4,640
Heating Season Total Capacity	34,245
Non-Heating Season Total Capacity	22,535
Total Entitlement	34,245
Total Annual Transportation	22,535
Total Season Transportation	11,710
Percent TF-5	31.16%
Total Percent Seasonal	34.19%

2017-2018 Heating Season G004/M-17-521	Quantity (dk)
FT-A (Cat. 3) (12 months)	8,000
FT-A (Cat. 3) (12 months)	5,000
FT-A (Cat. 3) (November - March)	2,000
FT-A (November - March)	-
BP Contract (Firm Demand)	1,600
TFX (12 months) 1/	13,000
TFX (November - March) 1/	2,000
TF-12 Base	4,854
TF-12 Variable	2,681
TF-5 (November- March)	3,410
TFX (November - March)	5,200
TFX - Negotiated (November - March)	1,000
TFX (Annual) 2/	2,000
TFX - Capacity Release	-
TF-12 - Capacity Release	-
FDD-1 Reservation 1/	4,640
Heating Season Total Capacity 3/	34,445
Non-Heating Season Total Capacity	22,535
Total Entitlement 3/	34,445
Total Annual Transportation 3/	21,235
Total Season Transportation	13,210
Percent TF-5	31.16%
Total Percent Seasonal	38.35%

2018-2019 Heating Season G004/M-18-____	Quantity (dk)	Difference
FT-A (Cat. 3) (12 months)	8,000	0
FT-A (Cat. 3) (12 months)	5,000	0
FT-A (Cat. 3) (November - March)	2,000	0
FT-A (November - March)	-	0
BP Contract (Firm Demand)	-	(1,600)
Proposed: Seasonal Capacity (Cat. 1)	2,400	2,400
TFX (12 months) 1/	13,000	0
TFX (November - March) 1/	2,000	0
TF-12 Base	4,854	0
TF-12 Variable	2,681	0
TF-5 (November- March)	3,410	0
TFX (November - March)	5,200	0
TFX - Negotiated (November - March)	1,000	0
TFX (Annual) 4/	2,000	0
TFX - Capacity Release	-	0
TF-12 - Capacity Release	-	0
FDD-1 Reservation 1/	4,640	0
Heating Season Total Capacity 5/	35,545	1,100
Non-Heating Season Total Capacity	22,535	0
Total Entitlement 5/	35,545	1,100
Total Annual Transportation 5/	21,535	300
Total Season Transportation	14,010	800
Percent TF-5	31.16%	0.00%
Total Percent Seasonal	39.41%	1.06%

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.
4/ Demand profile includes 1,000 dk: Remaining 1,000 dk used to deliver gas to Viking interconnect at Chisago for 1,000 dk FT-A (12 Months) 'back-haul' contract to Vergas, MN.
5/ Includes 1,000 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, 2018
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	$2.53010	$2.88560	$2.71910	$2.71910	7.5%	-5.8%	0.0%	$0.00000
GCR 5/	0.07620	0.17480	0.17480	0.17480	129.4%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26770	1.27020	1.28000	7.7%	1.0%	0.8%	0.00980
Commodity Margin 6/	1.91540	2.04710	1.91540	1.91540	0.0%	-6.4%	0.0%	0.00000
CCRA 7/	0.21250	0.20970	0.20970	0.20970	-1.3%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.14850	0.14850	0.14850	N/A	0.0%	0.0%	0.00000
RDM 10/			0.28420	0.28420	N/A	N/A	0.0%	0.00000
Total Rate	$5.92320	$6.74733	$6.73583	$6.74563	13.9%	0.0%	0.1%	$0.00980
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$461.42	$525.62	$524.72	$525.48	13.9%	0.0%	0.1%	$0.76
Firm General Service								
Commodity Cost of Gas	$2.53010	$2.88560	$2.71910	$2.71910	7.5%	-5.8%	0.0%	$0.00000
GCR 5/	0.07620	0.17480	0.17480	0.17480	129.4%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26770	1.27020	1.28000	7.7%	1.0%	0.8%	0.00980
Commodity Margin 6/	1.52380	1.63620	1.52380	1.52380	0.0%	-6.9%	0.0%	0.00000
CCRA 7/	0.21250	0.20970	0.20970	0.20970	-1.3%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.11170	0.11170	0.11170	N/A	0.0%	0.0%	0.00000
RDM 10/			0.24540	0.24540	N/A	N/A	0.0%	0.00000
Total Rate	$5.53160	$6.29963	$6.26863	$6.27843	13.5%	-0.3%	0.2%	$0.00980
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,402.93	$2,736.56	$2,723.09	$2,727.35	13.5%	-0.3%	0.2%	$4.26

	Commodity Change		Demand Change		Total Change		Avg. Annual
Customer Class	($/dk)	(Percent)	($/dk)	(Percent)	($/dk)	(Percent)	Bill Change
Residential	$0.0000	0.0%	$0.0098	0.8%	$0.0098	0.1%	$0.76
Firm General Service	0.0000	0.0%	0.0098	0.8%	0.0098	0.2%	$4.26

1/ Consolidated Base Cost of Gas effective July 1, 2017 in update to Docket No. G004/MR-16-834. Commodity margin effective January 1, 2018 in Docket No. G004/GR-15-879.
2/ Demand in Docket No. G004/AA-17-521, effective November 1, 2017:
3/ Most recently filed PGA: July 2018.
4/ Consolidated commodity and demand costs proposed in this docket, G004/M-18-___ effective November 1, 2018.
5/ GCR rate of $0.0762 (effective September 1, 2016 - Docket No. G004/AA-16-719); GCR rate of $0.1748 (effective September 1, 2017 - Docket No. G004/AA-17-493).
6/ Includes CCRC of $0.0556 (effective January 1, 2017 - Docket No. G004/M-16-384).
7/ CCRA of $0.2125 (effective January 1, 2017 - Docket No. G004/M-16-384); CCRA of $0.2097 (effective September 1, 2017 - Docket No. G004/M-17-338).
8/ Effective with service rendered on and after June 1, 2017 - Docket No. G004/M-16-495.
9/ Effective with service rendered on and after November 1, 2017 - Docket No. G004/M-16-1066.
10/ Effective with service rendered on and after January 1, 2018 - Docket No. G004/M-15-879.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2018
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	$2.53010	$2.88560	$2.71910	$2.71910	7.5%	-5.8%	0.0%	$0.00000
GCR 5/	0.16270	0.17480	0.17480	0.17480	7.4%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26770	1.27020	1.28000	7.7%	1.0%	0.8%	0.00980
Commodity Margin 6/	1.66470	1.54670	1.66470	1.66470	0.0%	7.6%	0.0%	0.00000
CCRA 7/	0.21250	0.20970	0.20970	0.20970	-1.3%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.14850	0.14850	0.14850	N/A	0.0%	0.0%	0.00000
RDM 10/			0.20030	0.20030	N/A	N/A	0.0%	0.00000
Total Rate	$5.75900	$6.24693	$6.40123	$6.41103	11.3%	2.6%	0.2%	$0.00980
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$448.63	$486.64	$498.66	$499.42	11.3%	2.6%	0.2%	$0.76
Firm General Service								
Commodity Cost of Gas	$2.53010	$2.88560	$2.71910	$2.71910	7.5%	-5.8%	0.0%	$0.00000
GCR 5/	0.16270	0.17480	0.17480	0.17480	7.4%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26770	1.27020	1.28000	7.7%	1.0%	0.8%	0.00980
Commodity Margin 6/	1.33480	1.25820	1.33480	1.33480	0.0%	6.1%	0.0%	0.00000
CCRA 7/	0.21250	0.20970	0.20970	0.20970	-1.3%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.11170	0.11170	0.11170	N/A	0.0%	0.0%	0.00000
RDM 10/			0.20080	0.20080	N/A	N/A	0.0%	0.00000
Total Rate	$5.42910	$5.92163	$6.03503	$6.04483	11.3%	2.1%	0.2%	$0.00980
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,358.40	$2,572.36	$2,621.61	$2,625.87	11.3%	2.1%	0.2%	$4.26

Customer Class	Commodity Change ($/dk)	Commodity Change (Percent)	Demand Change ($/dk)	Demand Change (Percent)	Total Change ($/dk)	Total Change (Percent)	Avg. Annual Bill Change
Residential	$0.0000	0.0%	$0.0098	0.8%	$0.0098	0.2%	$0.76
Firm General Service	0.0000	0.0%	0.0098	0.8%	0.0098	0.2%	$4.26

1/ Consolidated Base Cost of Gas effective July 1, 2017 in update to Docket No. G004/MR-16-834. Commodity margin effective January 1, 2018 in Docket No. G004/GR-15-879.
2/ Demand in Docket No. G004/AA-17-521, effective November 1, 2017:
3/ Most recently filed PGA: July 2018.
4/ Consolidated commodity and demand costs proposed in this docket, G004/M-18-___ effective November 1, 2018.
5/ GCR rate of $0.1627 (effective September 1, 2016 - Docket No. G004/AA-16-719); GCR rate of $0.1748 (effective September 1, 2017 - Docket No. G004/AA-17-493).
6/ Includes CCRC of $0.0556 (effective January 1, 2017 - Docket No. G004/M-16-384).
7/ CCRA of $0.2125 (effective January 1, 2017 - Docket No. G004/M-16-384); CCRA of $0.2097 (effective September 1, 2017 - Docket No. G004/M-17-338).
8/ Effective with service rendered on and after June 1, 2017 - Docket No. G004/M-16-495.
9/ Effective with service rendered on and after November 1, 2017 - Docket No. G004/M-16-1066.
10/ Effective with service rendered on and after January 1, 2018 - Docket No. G004/M-15-879.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT ANALYSIS

	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)
2018-2019	24,240	243	1.01%	33,674	941	2.87%	35,545	1,100	3.19%	5.56%
2017-2018	23,997	184	0.77%	32,733	335	1.03%	34,445	200	0.58%	5.23%
Annual Average			1.01%			2.87%			3.19%	5.40%

	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)
2018-2019				0.0772	1.3892	1.4664	
2017-2018	28,641	112	0.39%	0.0713	1.3640	1.4354	1.1935
Annual Average			0.39%	0.0743	1.3766	1.4509	1.1935