GREAT PLAINS
NATURAL GAS CO.
A Division of Montana-Dakota Utilities Co.

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June 28, 2019

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-19-___

Dear Mr. Wolf:

Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota Utilities Co., herewith electronically submits its Demand Entitlement Filing pursuant to Minnesota Rule 7825.2910, Subpart 2 for the 2019-2020 winter heating season.

Great Plains is requesting an increase in capacity of 400 Dk per day on Viking Gas Transmission (VGT) as shown on Exhibit B. Great Plains requests the additional capacity be effective November 1, 2019.

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

<u>Design Day Capacity Requirements</u>

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, its effects are immaterial and 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 34,066 Dk/day. This projection consists of 16,936 Dk/day for firm customers receiving natural gas from city gates interconnecting with VGT and 17,130 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.

Capacity Portfolio

Current

Transmission capacity currently subscribed to and effective November 1, 2018 totals 54,145 Dk/day. Within this value, 38,145 Dk/day directly interconnects to Great Plains' city gates. The remaining 16,000 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 20,000 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 18,000 Dk/day of annual capacity and 2,000 Dk/day of seasonal (Nov-Mar) capacity.

The currently held VGT capacity is sourced by 16,000 Dk/day of supplemental capacity on NNG's transmission system. The supplemental capacity on NNG consists of 14,000 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

[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.

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 18,145 Dk/day. Of this quantity, 8,535 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 2018-2019 heating season, Great Plains utilized 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).

Beginning in May 2019, Great Plains released 5,000 dk on a seasonal basis as reflected in the May 2019 Cost of Gas Adjustment.

Proposed

Great Plains proposes to utilize 400 dk of the current FT-A capacity release on VGT for incremental system capacity. This will lower the amount of capacity released from the authorized 2,600 Dk to 2,200 Dk for the 2019 – 2020 heating season as shown on Exhibit B, Page 1. The Company will update the Commission regarding the final capacity released by November 1, 2019.

Great Plains also proposes to release 1,000 Dk/day of currently contracted NNG capacity used as supplemental capacity to provide delivery from NNG market locations to the NNG/VGT interconnect (Chisago). The addition of the 5,000 Dk/day on VGT secured in late 2018, as explained in the November 2018 update in Docket No. G004/M-18-454, offsets the need for the 1,000 Dk/day of supplemental capacity to transport natural gas to Chisago. Great Plains proposes to post a capacity release in the same amount of the current supplemental capacity of 1,000 Dk/day on NNG's Customer Activity Site.

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 5.5 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 2017-2018, 2018-2019 and the proposed 2019-2020 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
FT-A - Zone 1-1 (Cat. 3)	5,000	4.3706	12	262,236
FT-A - Capacity Release	(2,200)	2.1300	5	(23,430)
FT-A - Capacity Release	(5,000)	0.9100	7	(31,850)
NNG				
TFX - Summer	13,000	5.6830	7	517,153
TFX - Winter	13,000	15.1530	5	984,945
TFX Seasonal (November - March)	2,000	15.1530	5	151,530
TF12 Base - Summer	3,819	5.6830	7	151,924
TF12 Base - Winter	3,819	10.2300	5	195,342
TF12 Variable - Summer	3,716	5.6830	7	147,826
TF12 Variable - Winter	3,716	13.8660	5	257,630
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 - Winter	1,000	26.8918	5	134,459
FDD-1 Reservation	4,640	1.7140	12	95,436
TFX - Capacity Release	(1,000)	4.0000	5	(20,000)
Interruptible Demand Credit				(347,114)
Total Demand Charges				$4,085,036

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, 2019 and Great Plains will provide a report to the Commission regarding the amount of the TF12 Base and TF12 Variable in place for the 2019-2020 heating season at that time. For purposes of isolating the rate impact of the demand portfolio for 2019-2020 the capacity release of 5,000 dk that runs through November 2019 was included in Table 1.

Exhibit C shows the impacts to customers due to the capacity changes discussed above. There is a decrease of 0.2 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 2019. The total customer impact of the updated demand profile compared to rates effective July 2019 is a decrease of $0.0033 per dk. Please see Table 2 below for the annual rate impacts reflecting the capacity and prices noted in Table 1 above and the capacity release of 5,000 dk that runs through November 2019.

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 28, 2019	($0.26)	-0.2	($1.43)	-0.2

<u>Demand Entitlement Analysis</u>

Exhibit D reflects the up-coming 2019-2020 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 2019 - 2020 HEATING SEASON
DESIGN DAY - NOVEMBER 2019

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) 5/	L&UA 6/	Projected Design	Proposed Capacity	Reserve
VGT												
Crookston	0.04733	0.01383	0.99645	96	2,579	2,601	1.37501	3,578	25	3,603		
North 4	0.05036	0.01397	0.99767	91	7,222	7,278	1.32163	9,622	67	9,689		
Wahpeton	0.07255	0.01412	0.99744	91	2,268	2,303	1.35747	3,619	25	3,644		
Total VGT					12,069	12,182		16,819	117	16,936		
NNG	0.05244	0.01626	0.99721	83	12,050	12,134	1.40202	17,011	119	17,130		
Total					24,119	24,316		33,830	236	34,066	35,945	5.5%

1/ Use per customer factors based on regression analysis for the 36 months ending March 2019.
2/ Design Heating Degree Days Base 60 degrees F.
3/ Reflects monthly average for December 2018 - February 2019.
4/ Customer growth is based on regression analysis for the 36 months ending March 2019 with composite growth rates of: Crookston = 0.85%, North = 0.78%, Wahpeton = 1.54%, South = 0.70%.
5/ Includes 500 dk of incremental capacity related to the addition of a new firm customer.
6/ Lost and Unaccounted for Gas percentage of 0.7%.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2019 - 2020 HEATING SEASON
DEMAND PROFILE EFFECTIVE NOVEMBER 1, 2019

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
FT-A - Zone 1-1 (Cat. 3)	5,000	0	5,000	5 years	10/31/23
FT-A - Capacity Release	(2,600)	400	(2,200)	5 months	3/31/20
NNG					
TF12 Base (Summer & Winter)	3,819	0	3,819	5 years	10/31/24
TF12 Variable (Summer & Winter)	3,716	0	3,716	5 years	10/31/24
TF5 (November - March)	3,410	0	3,410	5 years	10/31/24
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	10/31/24
TFX (Annual) 2/	1,000	1,000	2,000	10 years	10/31/25
TFX - Capacity Release	0	(1,000)	(1,000)	5 months	3/31/20
Subtotal	35,545	400	35,945		
Supplemental Capacity					
TFX Seasonal (November - March)	2,000	0	2,000	5 years	10/31/24
TFX (Annual)	13,000	0	13,000	11.5 years	3/31/24
TFX (Annual) 2/	1,000	(1,000)	0	10 years	10/31/25
Storage					
FDD-1 Reservation	4,640	0	4,640	5 years	5/31/24
Heating Season Total Capacity:	35,545	400	35,945		
Non-Heating Season Total Capacity:	27,535	(1,000)	26,535		
Forecasted Heating Season Design Day:	33,674	392	34,066		
Estimated Non-Heating Season Design Day:	18,507	(47)	18,460		
Heating Season Capacity: Surplus/(Shortage)	1,871	8	1,879		
Non-Heating Season Capacity: Surplus/(Shortage)	9,028	(953)	8,075		

1/ Minnesota communities plus Wahpeton, ND.
2/ Northern Natural capacity of 2,000 Dk, of which 1,000 Dk was formerly 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

2017-2018 Heating Season G004/M-17-521	Quantity (dk)	2018-2019 Heating Season G004/M-18-454	Quantity (dk)	2019-2020 Heating Season G004/M-19-____	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. 3) (12 months)	5,000	FT-A (Cat. 3) (12 months)	10,000	FT-A (Cat. 3) (12 months)	10,000	0
FT-A (Cat. 3) (November - March)	2,000	FT-A (Cat. 3) (November - March)	2,000	FT-A (Cat. 3) (November - March)	2,000	0
FT-A (November - March)	-	FT-A (November - March)	-	FT-A (November - March)	-	0
BP Contract (Firm Demand)	1,600	FT-A - Capacity Release	(2,600)	FT-A - Capacity Release	(2,200)	400
TFX (12 months) 1/	13,000	TFX (12 months) 1/	13,000	TFX (12 months) 1/	13,000	0
TFX (November - March) 1/	2,000	TFX (November - March) 1/	2,000	TFX (November - March) 1/	2,000	0
TF-12 Base	4,854	TF-12 Base	3,819	TF-12 Base	3,819	0
TF-12 Variable	2,681	TF-12 Variable	3,716	TF-12 Variable	3,716	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/	2,000	TFX (Annual) 4/	2,000	TFX (Annual)	2,000	0
TFX - Capacity Release	-	TFX - Capacity Release	-	TFX - Capacity Release	(1,000)	(1,000)
FDD-1 Reservation 1/	4,640	FDD-1 Reservation 1/	4,640	FDD-1 Reservation 1/	4,640	0
Heating Season Total Capacity 3/	34,445	Heating Season Total Capacity 5/	35,545	Heating Season Total Capacity	35,945	400
Non-Heating Season Total Capacity	22,535	Non-Heating Season Total Capacity	27,535	Non-Heating Season Total Capacity	26,535	(1,000)
Total Entitlement 3/	34,445	Total Entitlement 5/	35,545	Total Entitlement	35,945	400
Total Annual Transportation 3/	22,535	Total Annual Transportation 5/	26,535	Total Annual Transportation	27,535	1,000
Total Season Transportation	13,210	Total Season Transportation	9,010	Total Season Transportation	9,410	400
Percent TF-5	31.16%	Percent TF-5	31.16%	Percent TF-5	31.16%	0.00%
Total Percent Seasonal	38.35%	Total Percent Seasonal	25.35%	Total Percent Seasonal	26.18%	0.83%

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, 2019
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	$3.88920	$2.14980	$2.14980	-15.0%	-44.7%	0.0%	$0.00000
GCR 5/	0.07620	0.48590	0.48590	0.48590	537.7%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.33860	1.32820	1.32490	11.4%	-1.0%	-0.2%	(0.00330)
Commodity Margin 6/	1.65450	1.91540	1.65450	1.65450	0.0%	-13.6%	0.0%	0.00000
CCRA 7/	0.21250	0.01300	0.01300	0.01300	-93.9%	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	0.24940	0.24940	N/A	67.9%	0.0%	0.00000
RDM 10/		0.28420	(0.38160)	(0.38160)	N/A	-234.3%	0.0%	0.00000
Total Rate	$5.66230	$8.08873	$5.51313	$5.50983	-2.7%	-31.9%	-0.1%	($0.00330)
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$441.09	$630.11	$429.47	$429.21	-2.7%	-31.9%	-0.1%	($0.26)
Firm General Service								
Commodity Cost of Gas	$2.53010	$3.88920	$2.14980	$2.14980	-15.0%	-44.7%	0.0%	$0.00000
GCR 5/	0.07620	0.48590	0.48590	0.48590	537.7%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.33860	1.32820	1.32490	11.4%	-1.0%	-0.2%	(0.00330)
Commodity Margin 6/	1.31930	1.52380	1.31930	1.31930	0.0%	-13.4%	0.0%	0.00000
CCRA 7/	0.21250	0.01300	0.01300	0.01300	-93.9%	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	0.17920	0.17920	N/A	60.4%	0.0%	0.00000
RDM 10/		0.24540	(0.23120)	(0.23120)	N/A	-194.2%	0.0%	0.00000
Total Rate	$5.32710	$7.62153	$5.25813	$5.25483	-1.4%	-31.1%	-0.1%	($0.00330)
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,314.09	$3,310.79	$2,284.13	$2,282.70	-1.4%	-31.1%	-0.1%	($1.43)

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%	($0.0033)	-0.2%	($0.0033)	-0.1%	($0.26)
Firm General Service	0.0000	0.0%	(0.0033)	-0.2%	(0.0033)	-0.1%	($1.43)

1/ Consolidated Base Cost of Gas effective July 1, 2017 in update to Docket No. G004/MR-16-834. Commodity margin effective May 1, 2019 in Docket No. E,G-999/CI-17-895.
2/ Demand in Docket No. G004/AA-18-454, effective November 1, 2018:
3/ Most recently filed PGA: July 2019.
4/ Includes a seasonal capacity release of 5,000 Dk.
5/ GCR rate of $0.1748 (effective September 1, 2017 - Docket No. G005/AA-17-493); GCR rate of $0.4859 (effective September 1, 2018 - Docket No. G004/AA-18-374).
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 $0.0130 (effective October 1, 2018 - Docket No. G004/M-18-118).
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 and March 1, 2019 - Docket No. G004-M-18-282.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2019
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	$3.88920	$2.14980	$2.14980	-15.0%	-44.7%	0.0%	$0.00000
GCR 5/	0.16270	0.48590	0.48590	0.48590	198.6%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.33860	1.32820	1.32490	11.4%	-1.0%	-0.2%	(0.00330)
Commodity Margin 6/	1.65450	1.66470	1.65450	1.65450	0.0%	-0.6%	0.0%	0.00000
CCRA 7/	0.21250	0.01300	0.01300	0.01300	-93.9%	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	0.24940	0.24940	N/A	67.9%	0.0%	0.00000
RDM 10/		0.20030	(0.30500)	(0.30500)	N/A	-252.3%	0.0%	0.00000
Total Rate	$5.74880	$7.75413	$5.58973	$5.58643	-2.8%	-28.0%	-0.1%	($0.00330)
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$447.83	$604.05	$435.44	$435.18	-2.8%	-28.0%	-0.1%	($0.26)
Firm General Service								
Commodity Cost of Gas	$2.53010	$3.88920	$2.14980	$2.14980	-15.0%	-44.7%	0.0%	$0.00000
GCR 5/	0.16270	0.48590	0.48590	0.48590	198.6%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.33860	1.32820	1.32490	11.4%	-1.0%	-0.2%	(0.00330)
Commodity Margin 6/	1.31930	1.33480	1.31930	1.31930	0.0%	-1.2%	0.0%	0.00000
CCRA 7/	0.21250	0.01300	0.01300	0.01300	-93.9%	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	0.17920	0.17920	N/A	60.4%	0.0%	0.00000
RDM 10/		0.20080	(0.07420)	(0.07420)	N/A	-137.0%	0.0%	0.00000
Total Rate	$5.41360	$7.38793	$5.41513	$5.41183	0.0%	-26.7%	-0.1%	($0.00330)
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,351.67	$3,209.32	$2,352.33	$2,350.90	0.0%	-26.7%	-0.1%	($1.43)

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%	($0.0033)	-0.2%	($0.0033)	-0.1%	($0.26)
Firm General Service	0.0000	0.0%	(0.0033)	-0.2%	(0.0033)	-0.1%	($1.43)

1/ Consolidated Base Cost of Gas effective July 1, 2017 in update to Docket No. G004/MR-16-834. Commodity margin effective May 1, 2019 in Docket No. E,G-999/CI-17-895.
2/ Demand in Docket No. G004/AA-18-454, effective November 1, 2018:
3/ Most recently filed PGA: July 2019.
4/ Includes a seasonal capacity release of 5,000 Dk.
5/ GCR rate of $0.1748 (effective September 1, 2017 - Docket No. G005/AA-17-493); GCR rate of $0.4859 (effective September 1, 2018 - Docket No. G004/AA-18-374).
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 $0.0130 (effective October 1, 2018 - Docket No. G004/M-18-118).
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 and March 1, 2019 - Docket No. G004-M-18-282.
10/ Effective with service rendered on and after January 1, 2018 and April 1,2019 - 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)
2019-2020	24,316	76	0.31%	34,066	392	1.16%	35,945	400	1.13%	5.52%
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			0.70%			1.69%			1.63%	5.44%

	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)
2019-2020				0.0773	1.4010	1.4782	
2018-2019	30,320	1,679	5.86%	0.0772	1.3892	1.4664	1.2508
2017-2018	28,641	112	0.39%	0.0713	1.3640	1.4354	1.1935
Annual Average			3.13%	0.0753	1.3847	1.4600	1.2222