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

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1-877-267-4764

July 1, 2020

Mr. Will Seuffert
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-20-___

Dear Mr. Seuffert:

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 2020-2021 winter heating season.

Great Plains is requesting an increase of 200 dk per day on Viking Gas Transmission (VGT) and a decrease of 900 dk per day on Northern Natural Gas (NNG) as shown on Exhibit B. Great Plains requests the proposed capacity be effective November 1, 2020.

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 – Design Day Methodology Comparison

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, 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 33,922 Dk/day. This projection consists of 16,576 Dk/day for firm customers receiving natural gas from city gates interconnecting with VGT and 17,346 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>Design Day Methodology</u>

In compliance with the Commission's April 27, 2020 Order in Docket No. G004/M-19-430, Great Plains conducted a design day analysis based on daily data. These results are compared to the current design day methodology, based upon monthly data, and are included on Exhibit E. The daily design methodology shows a design day peak of 32,742 dk compared to Great Plains' currently approved method design day peak of 33,922 dk.

Several communities with large interruptible loads and small firm loads have seen sporadic gaps in data which impact the quality of data. Many of these same communities have only been collecting daily usage information since November of 2018. This also affects the quality and reliability of data to be used in the daily design methodology. As daily data is gathered and analyzed further, Great Plains will continue to evaluate the merits of transitioning to use of daily measurement data for use in design day forecasting. The two methodologies yield reasonably consistent results demonstrating two effective approaches to calculating a design day.

[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; Docket No. G004/M-17-521: Order dated May 15, 2018, and Docket No. G004/M-19-430: Order dated April 27, 2020.

Capacity Portfolio

Current

Transmission capacity currently subscribed to and effective November 1, 2019 totals 54,145 Dk/day. Within this value, 39,145 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 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 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. 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.

Proposed

Great Plains proposes to utilize 200 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 2,200 Dk to 2,000 Dk for the 2020 – 2021 heating season as shown on Exhibit B, Page 1. Great Plains also proposes to release 900 dk of TFX on NNG for the 2020 - 2021 heating season as also shown on Exhibit B, Page 1. The Company will update the Commission regarding the final capacities released by November 1, 2020.

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 6.8 percent for Great Plains' customers. The current abundance of supply, with the economic energy source natural gas provides, is spurring consumers using alternate fuel to convert to using 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 2018-2019, 2019-2020 and the proposed 2020-2021 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	$3.8060	12	$365,376
FT-A - Zone 1-1 (Cat. 3)	5,000	3.8060	12	228,360
FT-A Seasonal (Cat. 3)	2,000	3.8060	5	38,060
FT-A - Zone 1-1 (Cat. 3)	5,000	3.8060	12	228,360
FT-A - Capacity Release	(2,000)	0.9000	5	(9,000)
NNG				
TFX - Summer	13,000	7.3030	7	664,573
TFX - Winter	13,000	19.4710	5	1,265,615
TFX Seasonal (November - March)	2,000	19.4710	5	194,710
TF12 Base - Summer	3,921	7.3030	7	200,445
TF12 Base - Winter	3,921	13.1450	5	257,708
TF12 Variable - Summer	3,614	7.3030	7	184,751
TF12 Variable - Winter	3,614	17.8180	5	321,971
TF5	3,410	19.4710	5	331,981
TFX - Winter	5,200	19.4710	5	506,246
TFX - Annual (Summer Rate)	2,000	7.3030	7	102,242
TFX - Annual (Winter Rate)	2,000	19.4710	5	194,710
TFX Negotiated Contract - Winter	1,000	26.8918	5	134,459
FDD-1 Reservation	4,640	2.8624	12	159,378
Capacity Release	(900)	1.5000	5	(6,750)
Interruptible Demand Credit				(718,870)
Total Demand Charges				$4,644,325

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, 2020 and Great Plains will provide a report to the Commission regarding the amount of the TF12 Base and TF12 Variable in place for the 2020-2021 heating season at that time.

Exhibit C shows the impacts to customers due to the capacity changes discussed above. There is an increase of 0.4 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 2020. The total customer impact of the updated demand profile compared to rates effective July 2020 is an increase of $0.0056 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 (%)
July 1, 2020	$0.44	0.4	$2.43	0.4

<u>Demand Entitlement Analysis</u>

Exhibit D reflects the up-coming 2020-2021 heating season, on a consolidated basis, for the design day requirement, total entitlement and peak day design, entitlement and firm sendout per customer.

<u>Capacity Releases</u>

Great Plains will solicit interest in 2,000 dk/day of capacity on VGT's pipeline and 900 dk/day of capacity on NNG's pipeline in the upcoming 2020-2021 heating season to be released to others. These releases are shown Exhibit 1. Great Plains' preliminary discussion with potential third parties suggest less interest in this capacity for the upcoming heating season.

If you have any questions regarding this filing, please contact me at (701) 222-7855, or Brian M. Meloy, at (612) 335-1451.

Sincerely,

/s/ Travis R. Jacobson
Travis R. Jacobson
Director of Regulatory Affairs

cc: Brian M. Meloy

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2020 - 2021 HEATING SEASON
DESIGN DAY - NOVEMBER 2020

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	0.04450	0.01403	0.99575	96	2,595	2,622	1.39138	3,647	26	3,673		
North 4	0.05371	0.01393	0.99845	91	7,294	7,342	1.32134	9,706	68	9,774		
Wahpeton	0.06995	0.01417	0.99818	91	2,275	2,285	1.35942	3,107	22	3,129		
Total VGT					12,164	12,249		16,460	116	16,576		
NNG	0.05198	0.01642	0.99750	83	12,117	12,176	1.41484	17,225	121	17,346		
Total					24,281	24,425		33,685	237	33,922	36,245	6.8%

1/ Use per customer factors based on regression analysis for the 36 months ending March 2020.
2/ Design Heating Degree Days Base 60 degrees F.
3/ Reflects monthly average for December 2019 - February 2020.
4/ Customer growth is based on regression analysis for the 36 months ending March 2020 with composite growth rates of: Crookston = 1.04%, North = 0.66%, Wahpeton = 0.44%, South = 0.59%.
5/ Lost and Unaccounted for Gas percentage of 0.7%.

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2020 - 2021 HEATING SEASON
DEMAND PROFILE EFFECTIVE NOVEMBER 1, 2020

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	10/31/2022
FT-A - Zone 1-1 (Cat. 3)	5,000	0	5,000	5 years	10/31/2022
FT-A Seasonal - Zone 1-1 (Cat. 3)	2,000	0	2,000	5 years	10/31/2022
FT-A - Zone 1-1 (Cat. 3)	5,000	0	5,000	5 years	10/31/2023
FT-A - Capacity Release	(2,200)	200	(2,000)	5 months	3/31/2021
NNG					
TF12 Base (Summer & Winter)	3,921	0	3,921	5 years	10/31/2024
TF12 Variable (Summer & Winter)	3,614	0	3,614	5 years	10/31/2024
TF5 (November - March)	3,410	0	3,410	5 years	10/31/2024
TFX Negotiated (November - March)	1,000	0	1,000	10.5 years	3/31/2025
TFX Seasonal (November - March)	5,200	0	5,200	5 years	10/31/2024
TFX (Annual)	2,000	0	2,000	10 years	10/31/2025
TFX - Capacity Release	0	(900)	(900)	5 months	3/31/2021
Subtotal	36,945	(700)	36,245		
Supplemental Capacity					
TFX Seasonal (November - March)	2,000	0	2,000	5 years	10/31/2024
TFX (Annual)	13,000	0	13,000	11.5 years	3/31/2024
Storage					
FDD-1 Reservation	4,640	0	4,640	5 years	5/31/2024
Heating Season Total Capacity:	36,945	(700)	36,245		
Non-Heating Season Total Capacity:	27,535	0	27,535		
Forecasted Heating Season Design Day:	34,066	(144)	33,922		
Estimated Non-Heating Season Design Day:	18,460	192	18,652		
Heating Season Capacity: Surplus/(Shortage)	2,879	(556)	2,323		
Non-Heating Season Capacity: Surplus/(Shortage)	9,075	(192)	8,883		

1/ Minnesota communities plus Wahpeton, ND.

GREAT PLAINS NATURAL GAS CO.
DEMAND PROFILE

2018-2019 Heating Season G004/M-18-454	Quantity (dk)	2019-2020 Heating Season G004/M-19-430	Quantity (dk)	2020-2021 Heating Season G004/M-20-___	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)	10,000	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
FT-A - Capacity Release	(2,600)	FT-A - Capacity Release	(2,200)	FT-A - Capacity Release	(2,000)	200
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	3,819	TF-12 Base	3,921	TF-12 Base	3,921	0
TF-12 Variable	3,716	TF-12 Variable	3,614	TF-12 Variable	3,614	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)	2,000	TFX (Annual)	2,000	0
TFX - Capacity Release	-	TFX - Capacity Release	-	TFX - Capacity Release	(900)	(900)
FDD-1 Reservation 1/	4,640	FDD-1 Reservation 1/	4,640	FDD-1 Reservation 1/	4,640	0
Heating Season Total Capacity 3/	35,545	Heating Season Total Capacity	36,945	Heating Season Total Capacity	36,245	(700)
Non-Heating Season Total Capacity	27,535	Non-Heating Season Total Capacity	27,535	Non-Heating Season Total Capacity	27,535	0
Total Entitlement 3/	35,545	Total Entitlement	36,945	Total Entitlement	36,245	(700)
Total Annual Transportation 3/	26,535	Total Annual Transportation	27,535	Total Annual Transportation	27,535	0
Total Season Transportation	9,010	Total Season Transportation	9,410	Total Season Transportation	8,710	(700)
Percent TF-5	31.16%	Percent TF-5	31.16%	Percent TF-5	31.16%	0.00%
Total Percent Seasonal	25.35%	Total Percent Seasonal	25.47%	Total Percent Seasonal	24.03%	-1.44%

1/ Does not impact demand profile.
2/ 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.
3/ 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, 2020
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	$2.43770	$1.70310	$1.70310	-32.7%	-30.1%	0.0%	$0.00000
GCR 5/	0.07620	(0.23440)	(0.23440)	(0.23440)	-407.6%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26730	1.45680	1.46240	23.0%	15.4%	0.4%	0.00560
Commodity Margin 6/	1.65450	1.65450	1.65450	1.65450	0.0%	0.0%	0.0%	0.00000
CCRA 7/	0.21250	(0.03370)	(0.03370)	(0.03370)	-115.9%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.24940	0.00000	0.00000	N/A	-100.0%	N/A	0.00000
RDM 10/		(0.38160)	(0.20380)	(0.20380)	N/A	-46.6%	0.0%	0.00000
Total Rate	$5.66230	$4.97313	$4.35643	$4.36203	-23.0%	-12.3%	0.1%	$0.00560
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$441.09	$387.41	$339.37	$339.80	-23.0%	-12.3%	0.1%	$0.44
Firm General Service								
Commodity Cost of Gas	$2.53010	$2.43770	$1.70310	$1.70310	-32.7%	-30.1%	0.0%	$0.00000
GCR 5/	0.07620	(0.23440)	(0.23440)	(0.23440)	-407.6%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26730	1.45680	1.46240	23.0%	15.4%	0.4%	0.00560
Commodity Margin 6/	1.31930	1.31930	1.31930	1.31930	0.0%	0.0%	0.0%	0.00000
CCRA 7/	0.21250	(0.03370)	(0.03370)	(0.03370)	-115.9%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.17920	0.00000	0.00000	N/A	-100.0%	N/A	0.00000
RDM 10/		(0.23120)	(0.12440)	(0.12440)	N/A	-46.2%	0.0%	0.00000
Total Rate	$5.32710	$4.71813	$4.10063	$4.10623	-22.9%	-13.0%	0.1%	$0.00560
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,314.09	$2,049.56	$1,781.31	$1,783.75	-22.9%	-13.0%	0.1%	$2.43

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%	$0.0056	0.4%	$0.0056	0.1%	$0.44
Firm General Service	0.0000	0.0%	0.0056	0.4%	0.0056	0.1%	$2.43

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/M-19-430, effective November 1, 2019.
3/ Most recently filed PGA: July 2020.
4/ Includes seasonal capacity release of 2,000 Dk.
5/ GCR rate of $0.0762 (effective September 1, 2018 - Docket No. G004/AA-18-374); GCR rate of ($0.2344).
6/ Includes CCRC of $0.0556 (effective January 1, 2017 - Docket No. G004/GR-15-879).
7/ CCRA of $0.2125 (effective January 1, 2017 - Docket No. G004/M-16-384); CCRA rate of ($0.0337) (effective August 1, 2019 - Docket No. G004/M-19-273).
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 March 1, 2019 - Docket No. G004/M-18-282 and January 1, 2020 - Docket No. G004/M-19-273.
10/ Effective with service rendered on and after April 1, 2019 - Docket No. G004/GR-15-879; April 1, 2020 - Docket No. G004/M-20-335.

GREAT PLAINS NATURAL GAS CO.
RATE EFFECT OF PROPOSED DEMAND - NOVEMBER 1, 2020
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	$2.43770	$1.70310	$1.70310	-32.7%	-30.1%	0.0%	$0.00000
GCR 5/	0.16270	(0.23440)	(0.23440)	(0.23440)	-244.1%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26730	1.45680	1.46240	23.0%	15.4%	0.4%	0.00560
Commodity Margin 6/	1.65450	1.65450	1.65450	1.65450	0.0%	0.0%	0.0%	0.00000
CCRA 7/	0.21250	(0.03370)	(0.03370)	(0.03370)	-115.9%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.24940	0.00000	0.00000	N/A	-100.0%	N/A	0.00000
RDM 10/		(0.30500)	(0.20470)	(0.20470)	N/A	-32.9%	0.0%	0.00000
Total Rate	$5.74880	$5.04973	$4.35553	$4.36113	-24.1%	-13.6%	0.1%	$0.00560
Average Annual Usage (dk)	77.9	77.9	77.9	77.9				
Average Annual Cost of Gas	$447.83	$393.37	$339.30	$339.73	-24.1%	-13.6%	0.1%	$0.44
Firm General Service								
Commodity Cost of Gas	$2.53010	$2.43770	$1.70310	$1.70310	-32.7%	-30.1%	0.0%	$0.00000
GCR 5/	0.16270	(0.23440)	(0.23440)	(0.23440)	-244.1%	0.0%	0.0%	0.00000
Demand Cost of Gas	1.18900	1.26730	1.45680	1.46240	23.0%	15.4%	0.4%	0.00560
Commodity Margin 6/	1.31930	1.31930	1.31930	1.31930	0.0%	0.0%	0.0%	0.00000
CCRA 7/	0.21250	(0.03370)	(0.03370)	(0.03370)	-115.9%	0.0%	0.0%	0.00000
GAP 8/		0.01393	0.01393	0.01393	N/A	0.0%	0.0%	0.00000
GUIC 9/		0.17920	0.00000	0.00000	N/A	-100.0%	N/A	0.00000
RDM 10/		(0.07420)	0.00900	0.00900	N/A	-112.1%	0.0%	0.00000
Total Rate	$5.41360	$4.87513	$4.23403	$4.23963	-21.7%	-13.0%	0.1%	$0.00560
Average Annual Usage (dk)	434.4	434.4	434.4	434.4				
Average Annual Cost of Gas	$2,351.67	$2,117.76	$1,839.26	$1,841.70	-21.7%	-13.0%	0.1%	$2.43

	Commodity Change		Demand Change		Total Change		Avg. Annual
Customer Class	($/dk)	(Percent)	($/dk)	(Percent)	($/dk)	(Percent)	Bill Change
Residential	$0.0000	0.0%	$0.0056	0.4%	$0.0056	0.1%	$0.44
Firm General Service	0.0000	0.0%	0.0056	0.4%	0.0056	0.1%	$2.43

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/M-19-430, effective November 1, 2019.
3/ Most recently filed PGA: July 2020.
4/ Includes seasonal capacity release of 2,000 Dk.
5/ GCR rate of $0.0762 (effective September 1, 2018 - Docket No. G004/AA-18-374); GCR rate of ($0.2344).
6/ Includes CCRC of $0.0556 (effective January 1, 2017 - Docket No. G004/GR-15-879).
7/ CCRA of $0.2125 (effective January 1, 2017 - Docket No. G004/M-16-384); CCRA rate of ($0.0337) (effective August 1, 2019 - Docket No. G004/M-19-273).
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 March 1, 2019 - Docket No. G004/M-18-282 and January 1, 2020 - Docket No. G004/M-19-273.
10/ Effective with service rendered on and after April 1, 2019 - Docket No. G004/GR-15-879; April 1, 2020 - Docket No. G004/M-20-335.

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)
2020-2021	24,425	109	0.45%	33,922	(144)	-0.42%	36,245	(700)	-1.89%	6.85%
2019-2020	24,316	76	0.31%	34,066	392	1.16%	36,945	1,400	3.94%	8.45%
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			0.64%			1.16%			1.46%	6.52%

	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)
2020-2021				0.0951	1.3888	1.4839	
2019-2020	28,451	(1,869)	-6.16%	0.1184	1.4010	1.5194	1.1701
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			0.03%	0.0905	1.3858	1.4763	1.2048

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2020 - 2021 HEATING SEASON
DESIGN DAY METHODOLOGY COMPARISON

	Approved Method		Daily Method	
Pipeline	Proposed Design	Reserve	Proposed Design	Reserve
VGT	16,576		16,338	
NNG	17,346		16,404	
Total	33,922	6.8%	32,742	10.7%