January 27, 2020

Ryan Barlow
Acting Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G004/M-19-430

Dear Mr. Wolf:

Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department), in the following matter:

> Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Company (Great Plains or the Company) Demand Entitlement Filing (Petition).

The Petition was filed on June 28, 2019 and supplemented on November 1, 2019 by:

> Tamie A. Aberle
> Director of Regulatory Affairs
> Great Plains Natural Gas Company
> 705 West Fir Avenue
> PO Box 176
> Fergus Falls, Minnesota 56538-0176

Based on its review, the Department recommends that the Minnesota Public Utilities Commission (Commission):

- Accept the Company's proposed level of demand entitlement;
- Allow Great Plains to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2019; and
- Require Great Plains to conduct a design-day analysis based on daily data in its next demand entitlement filing and compare these results to its current design-day method.

The Department is available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ ADAM J. HEINEN
Public Utilities Rates Analyst

AJH/ja
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G004/M-19-430

I. SUMMARY OF THE UTILITY'S PROPOSAL

Pursuant to Minnesota Rules part 7825.2910, subpart 2, Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Company (Great Plains or the Company), filed a petition on June 28, 2019 with the Minnesota Public Utilities Commission (Commission) to change the levels of demand for natural gas pipeline capacity (Petition). The Petition is the third in which the Company's South District and North District were combined based on the Commission's September 6, 2016 Order in Docket No. G004/GR-15-879.

On November 1, 2019, Great Plains made its November Supplemental Filing (Supplement) detailing final entitlement levels for the 2019-2020 heating season. The Supplement includes final updated demand rates and commodity pricing. In its Supplement, Great Plains adjusted the originally proposed entitlement levels in its Petition.

For the area of the Company's system that was previously known as the North District, Great Plains requested that the Commission accept a 400 Dekatherm (Dkt) per day (Dkt/day) decrease in its expected capacity release for forward haul on the Viking Gas Transmission Company (Viking) system. This results in an increase in available capacity to serve firm customers who receive delivery from the Viking pipeline. The proposed capacity in this area for the 2019-2020 heating season is an increase of 400 Dkt/day from the 2018-2019 heating season.[1]

For the area of the Company's system that was previously known as the South District, Great Plains proposed to increase the amount of Northern Natural Gas Company's (NNG or Northern) capacity by 1,000 Dkt/day. This increase in deliverable capacity to customers served off Northern involves shifting the capacity from supplemental capacity to direct capacity. In the past, this capacity was used to facilitate backhaul transportation for Great Plains' customers served off the Viking pipeline.[2]

[1] Supplement, Page 2.
[2] Petition, Exhibit B, Page 1 of 2.

The Company projected an 8.45 percent reserve margin for the upcoming heating season.[3]
Great Plains estimated that its proposal would cause an increase in rates for residential customers of $0.0089 per dekatherm or approximately $0.69 per year for customers assuming an annual usage of 77.9 Dkt.

Great Plains requested that the Commission allow recovery of the associated demand costs in the Company's monthly Purchased Gas Adjustment (PGA) effective November 1, 2019.

II. DEPARTMENT ANALYSIS

The Minnesota Department of Commerce, Division of Energy Resources' (Department) analysis of the Company's request includes the following areas:

- Great Plains' proposed changes to the overall demand entitlement levels and non-capacity items;
- The design-day requirements;
- The reserve margin;
- Distribution planning; and
- The PGA cost recovery proposal.

A. GREAT PLANS' PROPOSED CHANGES TO THE OVERALL DEMAND ENTITLEMENT LEVELS AND NON-CAPACITY ITEMS

1. Changes to the Entitlement Levels

As indicated in Department Attachment 1 and noted above, the Company proposed to increase its entitlement levels as follows:

Table 1: Great Plains' Total Entitlement Levels

November 1, 2019 Filing	Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Change (Dkt)	% Change from Previous Year
Viking	17,400	17,800	400	2.30%
Northern	18,145	19,145	1,000	5.51%
Total	35,545	36,945	1,400	3.94%

Table 2 below provides Great Plains' specific changes to its overall level of contracted capacity.

[3] Supplement, Exhibit A.

Table 2: Comparison of MERC's Current and Proposed Entitlements

Contract Type	Previous Entitlement Level (Dkt)	Proposed Entitlement Level (Dkt)	Proposed Change in Entitlement Level (Dkt)
FT-A Capacity Release	(2,600)	(2,200)	400
TFX-12	1,000	2,000	1,000
TF-12B (Base)	3,819	3,921	102
TF-12V (Variable)	3,716	3,614	(102)

In in terms of NNG capacity, Great Plains stated in its initial filing that Northern's reallocation of TF-12B and TF-12V services is based on the amount of capacity used during the preceding May through September period and was unknown at the time of its initial filing.[4] The Company's Supplement provided the TF-12B and TF-12V reallocation, as shown in Table 2 above.[5] The reallocation changes are in accordance with NNG's tariff approved by the Federal Energy Regulatory Commission (FERC). Usually there is no deliverability difference between TF-12B and TF-12V services, but TF-12B service is less expensive than TF-12V service.

As shown in Table 2 above, there was an increase of 1,000 Dkt/day in the aggregate volume of Northern capacity year-over-year. This increase in capacity is related to Northern capacity that was formerly used as supplemental capacity for delivery of gas to Viking at Chisago for backhaul to Vergas, MN.[6] In its Petition, Great Plains stated that it anticipated offsetting this increase in capacity by releasing 1,000 Dkt/day in capacity on the Northern system;[7] however, as noted in its Supplement, the Company was unable to secure a purchaser at the time of its filing. Great Plains stated that it is in ongoing discussions with purchasers and will provide and update if this capacity release is finalized.[8] The Department requests that Great Plains provide an update on these discussions in its reply comments.

In terms of Viking capacity, Great Plains proposed to utilize 400 Dkt/day of the current FT-A capacity release for incremental system capacity.[9] The Company confirmed in its Supplement that it was able to secure a contract from the remainder of the 2,200 Dkt/day of capacity release for the 2019-2020 heating season.[10]

The Department analyzes below the proposed changes, the proposed design-day requirements, and the proposed reserve margin for Great Plains.

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[4] Petition, Pages 4-5.
[5] Supplement, Exhibit B, Page 1 of 2.
[6] Petition, Exhibit B, Page 1 of 2.
[7] Petition, Page 3.
[8] Supplement, Page 2.
[9] Petition, Page 3.
[10] Supplement, Page 2.

2. *Changes to Non-Capacity and Non-Design-Day Deliverable Items*

Great Plains did not propose changes to its non-capacity items such as Firm Deferred Delivery (FDD) on Northern in this demand entitlement filing. The Department notes that these items, such as storage, can be used as part of an integrated purchasing strategy to reduce baseload winter gas purchases and overall commodity price volatility.

As noted in Section II.A.1 above, Great Plains did decrease its supplemental capacity on Northern by 1,000 Dkt/day. This decrease in supplemental capacity does not impact design-day deliverability because an equal amount of Viking capacity is counted toward the design-day requirement. In the past, this supplemental Northern capacity was used as backhaul to provide that deliverable capacity on the Viking pipeline system to Vergas, MN. Supplemental capacity is required in a backhaul situation because physical supply on the Northern system is not able to flow "backwards" on the Viking system from Chisago upstream to deliverable points on the Great Plains system. The purpose of the backhaul contract is to create a transaction where capacity injected into Viking at Chisago, from Northern, effectively counteracts an equal amount of capacity on Viking that was withdrawn for use at a delivery point upstream from Chisago.

B. DESIGN-DAY REQUIREMENTS

As indicated in Department Attachment 1, the Company proposed to increase its total design day in Dkt as follows:

Table 3: Great Plains Design-Day Levels

Supplemental Filing	Previous Design Day (Dkt)	Proposed Design Day (Dkt)	Design Day Changes (Dkt)	% Change from Previous Year
North-4	9,693	9,689	(4)	(0.04)%
Crookston	3,592	3,603	11	0.31%
Wahpeton	3,187	3,644	457	14.64%
Total Viking	16,472	16,936	464	2.82%
South (Northern)	17,202	17,130	(72)	(0.42)%
Total	33,674	34,066	392	1.16%

As shown on Petition Exhibit A and Table 3 above, Great Plains calculated a projected design-day requirement of 34,066 Dkt/day. This projection consists of 16,936 Dkt/day for firm customers receiving natural gas from city gates interconnecting with Viking and 17,130 Dk/day for those firm customers receiving natural gas from city gates interconnecting with Northern.

Great Plains used the same basic design-day method in this docket that the Commission accepted in Docket No. G004/M-03-303. In previous demand entitlement proceedings, the Department and Commission Staff expressed concerns that Great Plains' design-day method might under-estimate the need for natural gas on a peak day for the South District and the North District.[11] In response to these concerns, the Commission ordered the Company and the Department to work cooperatively on developing a design-day analysis that would address the concerns raised by the Department.[12] Great Plains and the Department worked on this issue subsequent to the Commission Order and, although certain concerns with sample size still existed,[13] the Commission determined that the Company's design-day methodology was acceptable because its results were not unreasonable.[14] In a subsequent demand entitlement filing, the Department noted the possibility of serial correlation[15] in the Company's design-day analysis.[16] Serial correlation is a statistical issue that violates the requirements of regression analysis and can result in biased results. As such, in its Order for the 2016 demand entitlement filing, the Commission required Great Plains to check its models for serial correction, and correct the models if serial correlation is present, in future demand entitlement filings.[17]

On the topic of serial correction, Great Plains stated the following:[18]

> 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 agree 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.

Great Plains partially complied with the Commission's Order in Docket No. G004/M-16-557 by checking its models for autocorrelation; however, Great Plains did not correct the models for serial correlation. In the 2017 demand entitlement filing, the Department stated that it does not advocate that Great Plains purchase statistical software for the sole purpose of addressing serial correlation in the Company's models and agreed that this is not an appropriate cost for Great Plains to pass on to its customers.[19] The Company's decision to monitor serial correlation in its models, as opposed to

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[11] The Department's concerns on this issue are discussed in detail in the following documents:
- July 2, 2008 Department Comments in Docket No.G004/M-07-1401;
- July 31, 2009 Department Comments in Docket No. G004/M-08-1306; and
- February 5, 2010 Department Comments in Docket No.G004/M-09-1262.
  Commission Staff's concerns are discussed in detail in its September 9, 2010 *Briefing Papers*, which were contemporaneously submitted in each of these three dockets.

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

[13] The Department's concerns on this issue are discussed in detail in the following documents: the Department's March 18, 2013 *Comments* in Docket No. G004/M-12-740; and the Department's August 19, 2013 *Comments* in Docket No. G004/M-13-566.

[14] January 9, 2014 Order, Docket No. G004/M-12-740.

[15] Serial correlation may also be referred to as autocorrelation.

[16] Docket No. G004/M-15-645.

[17] June 8, 2017 Order, Docket No. G004/M-16-577.

[18] Petition, Page 2.

[19] Docket No. G004/M-17-521, November 29, 2017 Department Comments, Page 6.

correcting it, is not unreasonable at this time. The Department reviews the Company's models and addresses the issue of serial correlation below.

The Department previously discussed the issue of serial correlation and its potential impact and will not repeat that discussion here.[20] The Department continues to conclude that Great Plains need not purchase statistical software for the sole purpose of addressing serial correlation; therefore, the Department reviewed the Company's models and corrected for serial correlation where appropriate.[21]

The Department's corrected models result in a total system design-day estimate of 34,246 Dkt/day.[22] This estimate is 180 Dkt/day, or 0.53 percent, greater than Great Plains' proposed design-day estimate of 34,066 Dkt/day.[23] On a pipeline basis, the Department's corrected models estimate 17,062 Dkt/day for deliverability on Viking, which is 126 Dkt/day greater than Great Plains' proposed figure of 16,936 Dkt/day, and 17,184 Dkt/day for deliverability on Northern, which is 54 Dkt/day greater than Great Plains' proposed figure of 17,130 Dkt/day.

Given the small difference between these design-day estimates, and the nature of purchasing capacity on interstate pipelines, the Department concludes that Great Plains' models can be used by Great Plains in planning for its design day at this time. Although correcting the models for serial correlation results in an increase in the estimated design day, the difference is such that the Company is unlikely to find available capacity in the open market that would meet this need without also increasing the reserve margin. Interstate pipelines sell capacity in long-term contracts that are typically for hundreds or thousands of Dkts per day. More importantly, the Company's proposed reserve margin of 8.45 percent adequately accounts for the small entitlement difference. The Department does not believe that failing to correct for serial correlation will impair firm reliability on a peak day at this time.

Consistent with its review in previous demand entitlement filings,[24] the Department used two other methods to gauge the reasonableness of the Company's design-day amounts for Great Plains' system: 1) using data from the previous 5 heating seasons; and 2) using data from the heating season with the overall greatest peak sendout per firm customer that occurred before the previous 5 heating seasons.[25]

During the last heating season, Great Plains' service territory, and the entire state of Minnesota, experienced a significant cold weather outbreak in late January and early February. This cold weather event marked the coldest conditions since the 1995-1996 heating season and resulted in near design-day conditions. These conditions resulted in the greatest peak sendout per firm customer during the

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[20] See the Department's *August 27, 2015 Comments* in Docket No. G004/M-15-645, Pages 4-5; *November 10, 2016 Response Comments* in Docket No. G004/M-16-557, Page 8; and the Department's *November 29, 2017, Comments* in Docket No. G004/M-17-521, Pages 4-8.
[21] Department Attachment 2.
[22] Department Attachment 3.
[23] Petition, Exhibit A.
[24] *See* Docket Nos. G004/M-11- 1075, G004/M-12-740, and G011/M-13-566.
[25] The data used by the Department is taken from Exhibit D of the Company's Petition and prior demand entitlement filings.

last 5 heating seasons. The Department multiplied the peak sendout per firm customer for the 2018-2019 heating season of 1.2508 Dkt per customer by the expected number of firm customers for the 2019-2020 heating season of 24,316 to arrive at an estimated design-day amount of 30,414 Dkt/day. This amount is 3,652 Dkt/day less than the Company's proposed design-day level of 34,066 Dkt/day. Thus, using the method based on the highest firm peak sendout data for the previous 5 heating seasons, Great Plains appears to have sufficient entitlements for the 2019-2020 heating season to ensure firm reliability for conditions similar to the 2018-2019 heating season.[26] In addition, the Department notes that the peak firm sendout during the 2018-2019 heating season of 30,320 Dkt was 3,354 Dkt less than the Company's design-day estimate in its last demand entitlement filing.[27] This also suggests that Great Plains has sufficient entitlements to serve firm customers during design-day conditions.

In Great Plains' 2015 general rate case (Docket No. G004/GR-15-879), the Commission approved the consolidation of Great Plains' North and South PGA districts.[28] Prior to this consolidation, Great Plains calculated design-day estimates, and collected data, on a North and South district basis. Prior to this consolidation, the South District's 1995-1996 heating season represented the highest peak sendout per firm customer in the previous 23 heating seasons. The peak sendout for the former South District was 1.5197 Dkt/day per customer. The North District experienced its highest peak sendout per firm customer in the previous 23 heating seasons during the 1999-2000 heating season. The peak sendout for the former North District was 1.5322 Dkt/day per customer.

Using the peak sendout data for the former North District, the Department calculated an estimated design-day amount for the Great Plains system. As noted above, the expected number of firm customers for the 2019-2020 heating season is 24,316 and, when this is multiplied by the 1999-2000 heating season peak sendout of 1.5322 Dkt/day, it results in an estimated peak sendout of 37,257 Dkt/day. This amount is 312 Dkt greater than the Company's proposed total entitlement level of 36,945 Dkt/day. The Department also used peak-day sendout data for the former South District to estimate peak-day sendout for the 2019-2020 heating season. Using the 1.5197 Dkt/day per customer from the 1995-1996 heating season, the Department estimated peak day sendout of 36,953 Dkt/day based on an estimated firm customer count of 24,316. This amount is 8 Dkt greater than the Company's proposed total entitlement level of 36,945 Dkt/day.

At first glance, this historical analysis suggests that Great Plains may not have sufficient capacity to serve firm customers on a peak day. However, as noted above, Great Plains' system experienced near peak day conditions during the 2019-2020 heating and only experienced peak sendout per customer of 1.2508 Dkt/day. This peak sendout result suggests that the characteristics of firm usage on the Great Plains system have changed; namely, that firm customers use less during near-peak day conditions than they did in the 1990s and early 2000s. In a previous demand entitlement proceeding, both Great

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[26] Department Attachment 1.
[27] *Id.*
[28] September 6, 2016 Order, Docket No. G004/GR-15-879.

Plains and the Department observed that changes in firm usage patterns may occur over time and should be considered in estimates of peak-day use per customer.[29]

Based on its analysis, and the performance of Great Plains' system during the 2019-2020 heating season, the Department recommends that the Commission accept the Company's design-day method.

Although Great Plains' design-day method is acceptable at this time, the Department notes that the method does not represent the most appropriate method to estimate peak-day usage. The most appropriate method is to use daily heating season data to estimate peak-day consumption as opposed to the monthly sales data used by Great Plains. A daily model is preferable to a monthly model because the daily model estimates usage for a specific day, which the design day is created for, while the monthly model estimates average consumption over an entire month. Although these two models both appropriately estimate a customer's reaction to changes in temperature, or other factors, the consumption relationship may differ between peak and average temperatures.

In the past, gas utilities were unable to use daily models because daily customer-class-specific data was largely unavailable because telemetry and automated metering was unavailable for non-firm customers. With the introduction of these metering processes, many gas utilities are now able to conduct daily throughput analyses. The Department notes that Great Plains provided to the Department estimated daily firm consumption for the cold weather event during the 2018-2019 heating season in Docket No. E,G999/CI-19-160.[30] The Department recommends that the Commission require Great Plains to conduct a design-day analysis based on daily data in its next demand entitlement filing and compare these results to its current design-day method.

C. RESERVE MARGIN

As indicated in Department Attachment 1 and Supplement Exhibit A, and summarized in Table 4 below, the proposed reserve margin is 2,879 Dkt/day, or 8.45 percent.

Table 4: Great Plains' Reserve Margin

Pipeline	Total Entitlement (Dkt)	Design-Day Estimate (Dkt)	Difference (Dkt)	2019/2020 Reserve Margin (%)	2018/2019 Reserve Margin (%)	Percentage Point Change From Prior Year
Viking	17,800	16,936	864	5.10%	4.92%	0.18%
Northern	19,145	17,130	2,015	11.76%	5.52%	6.24%
Total	36,945	34,066	2,879	8.45%	5.20%	3.25%

[29] Docket No. G004/M-10-1164.
[30] June 28, 2019 Great Plains Reply Comments, Docket No. E,G999/CI-19-160.

In the Company's 2007, 2008, and 2009 demand entitlement proceedings, the Commission stated the following:[31]

> Great Plains shall reduce its reserve margin in Docket No. G004/M-09-1262 to approximately five percent or explain why it is not reasonable to do so.

Although the Company's 8.45 percent reserve margin is greater than the 5 percent reserve margin reference in the above Commission Order, the Department notes that the increase in the reserve margin from the last heating season is driven by the Company's inability to release 1,000 Dkt/day of capacity on Northern that it originally proposed to release.[32] If the Company had been able to release this capacity, its proposed reserve margin for the 2019-2020 heating season would be 5.50 percent,[33] which is close to the 5 percent threshold referenced above. Despite the higher reserve margin, the Department concludes that the Company's reserve margin is not unreasonable. In addition, the Department makes two points. First, Great Plains is actively attempting to release the 1,000 Dkt/day of capacity, which suggests that the Company is aware of any potential excess capacity and is attempting to mitigate these concerns.[34] Second, the Company's current capacity contracts do not expire until 2022 to 2025, depending on the contract; as such, Great Plains is unable to permanently reduce capacity, if necessary, until these contracts expire.[35] Therefore, the capacity release market represents the Company's most appropriate method to manage its reserve margin at this time.

D. DISTRIBUTION PLANNING AND RELIABILITY

In recent demand entitlement filings, the Department requested information from Great Plains, and conducted analyses, regarding the Company's distribution planning and the integration of electric generation onto the Great Plains' system. In last year's demand entitlement, the Department concluded that the Company's current planning approach is reasonable.[36]

In response to the cold weather event in January 2019, the Commission opened an investigation in Docket No. E,G999/CI-19-160 to assess utility responses to cold weather and system reliability. As noted above, and discussed at length in Docket No. E,G999/CI-19-160, Great Plains did not experience deliverability issues during the cold weather event in late January 2019; however, the Company did experience pressure issues in Fergus Falls. Given these pressure issues, the Commission required Great Plains to provide information regarding this event in its next demand entitlement filing.[37]

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[31] *See* 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.
[32] Petition, Page 3.
[33] Petition, Exhibit A.
[34] Supplement, Page 2.
[35] Supplement, Exhibit B.
[36] Docket No. G004/M-18-454, Department Response Comments, Page 10.
[37] October 15, 2019 Order, Docket No. G004/M-18-454.

Since the Commission's Order in Docket No. G004/M-18-454 occurred after the filing of the Petition, and near filing of the Supplement, the Company did not address the Fergus Falls pressure event. Given the lack of this discussion, the Department issued discovery requesting the information required in the Order. In its response to Department Information Request No. 2, Great Plains provided the required information.[38]

The Company noted that the pressure issues occurred in an outlying area near Fergus Falls on January 29, 2019 and was related to a feed to a distribution regulator station. In response to this issue, Great Plains personnel monitored and checked pressures manually throughout the evening of January 29 and into the morning of January 30. There was no loss of service because of the pressure issue, and the Company was prepared to curtail interruptible customers if needed to maintain system integrity. Subsequent to the pressure issue, the Company analyzed the impacted area and replaced a 2-inch PVC main with a 4-inch main and the larger main entered service on October 14, 2019. Based on Great Plains' discovery response, it appears that the Company responded adequately to the pressure event in Fergus Falls and has taken appropriate steps to correct this issue. The Department does not have additional concerns at this time.

Although not typically discussed in demand entitlement filings, distribution planning is an important part of providing reliable service to ratepayers. The procurement of capacity, as reflected in the demand entitlement proceedings, is meant to satisfy total daily firm need on a peak day, while distribution system planning is intended to ensure sufficient capacity is available to meet maximum gas need at a particular time and location. Given the potential for reliability issues during an extreme cold event, the Department issued new discovery in an effort to understand Great Plains' distribution planning assumptions. In its response to Department Information Request No. 1, the Company provided an explanation of its distribution planning method and various assumptions built into its analysis.[39] Great Plains stated that it has historically modeled system changes necessary to accommodate new loads and monitored its actual system pressures at a border station level during cold weather events in order to identify potential future upgrades. The Company further stated that it has recently employed distribution system planning models that will be updated and reviewed annually in order to analyze distribution capacity requirements. Great Plains noted that its new modeling uses weather assumptions that are based on the simple average of the coldest day in the last 30 years.

The Department appreciates the Company's explanation and clarification of its distribution planning assumptions. Based on this information, the Department concludes that Great Plains' planning assumptions appear acceptable at this time.

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[38] Department Attachment 4.
[39] Department Attachment 5. The Department notes that Department Information Request No. 1 is a new request for information that has not been asked in previous reliability, integration, or distribution planning analyses.

E. PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed above and in the Company's Supplement represent the demand entitlements for which Great Plains' firm customers would pay. In its Supplement, the Company compared its October 2019 PGA to the projected November 2019 PGA rates to highlight the changes in demand costs.[40] Great Plains presented an analysis indicating that the Company's demand entitlement proposal would result in the following estimated annual rate impacts for customers. The Company presented these impacts for both its former North and South District area; however, the impact on customers does not differ between the two former PGA districts. The rate impacts are as follows:

- an annual bill increase of approximately $0.69, or 0.7 percent, for the average residential customer consuming 77.9 Dkt annually; and
- an annual bill increase of approximately $3.87, or 0.7 percent, for the average firm general service customer consuming 434.4 Dkt annually.

III. THE DEPARTMENT'S RECOMMENDATIONS

Based on its review, the Department recommends that the Commission:

- Accept the Company's proposed level of demand entitlement;
- Allow Great Plains to recover associated demand costs through the monthly Purchased Gas Adjustment effective November 1, 2019; and
- Require Great Plains to conduct a design-day analysis based on daily data in its next demand entitlement filing and compare these results to its current design-day method.

The Department also requests that Great Plains provide in Reply Comments an update regarding ongoing discussions with purchasers regarding capacity release for its Northern contracts.

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[40] Supplement, Exhibit C.

Department Attachment 1
Docket No. G004/M-19-430
Great Plains Demand Entitlement Analysis*

	Number of Firm Customers			**Design-Day Requirement**			**Total Entitlement Plus Peak Shaving**			**Reserve Margin**	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve (7) - (4)	% Reserve [(7)-(4)]/(4)
2019-2020	24,316	76	0.31%	34,066	392	1.16%	36,945	1,400	3.94%	2,879	8.45%
2018-2019	24,240	243	1.01%	33,674	941	2.87%	35,545	1,100	3.19%	1,871	5.56%
2017-2018	23,997	184	0.77%	32,733	335	1.03%	34,445	200	0.58%	1,712	5.23%
2016-2017	23,813	(69)	-0.29%	32,398	131	0.41%	34,245	700	2.09%	1,847	5.70%
2015-2016	23,882	358	1.52%	32,267	1,143	3.67%	33,545	900	2.76%	1,278	3.96%
2014-2015	23,524	296	1.27%	31,124	1,691	5.75%	32,645	2,000	6.53%	1,521	4.89%
2013-2014	23,228	290	1.26%	29,433	339	1.17%	30,645	0	0.00%	1,212	4.12%
2012-2013	22,938	164	0.72%	29,094	158	0.55%	30,645	159	0.52%	1,551	5.33%
2011-2012	22,774	40	0.18%	28,936	(393)	-1.34%	30,486	(1,380)	-4.33%	1,550	5.36%
2010-2011	22,734	(2)	-0.01%	29,329	(515)	-1.73%	31,866	(1,170)	-3.54%	2,537	8.65%
2009-2010	22,736	85	0.38%	29,844	119	0.40%	33,036	(1,170)	-3.42%	3,192	10.70%
2008-2009	22,651	49	0.22%	29,725	(714)	-2.35%	34,206	0	0.00%	4,481	15.07%
2007-2008	22,602	1	0.00%	30,439	(406)	-1.32%	34,206	0	0.00%	3,767	12.38%
2006-2007	22,601			30,845			34,206			3,361	10.90%
Average			0.57%			0.79%			0.64%		7.59%

	Firm Peak-Day Sendout			**Per Customer Metrics**			
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak-Day Sendout (Dth)	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 Send per Customer (12)/(1)
2019-2020	unknown			0.1184	1.4010	1.5194	unknown
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
2016-2017	28,529	1,283	4.71%	0.0776	1.3605	1.4381	1.1980
2015-2016	27,246	(1,853)	-6.37%	0.0535	1.3511	1.4046	1.1409
2014-2015	29,099	1,406	5.08%	0.0647	1.3231	1.3877	1.2370
2013-2014	27,693	3,471	14.33%	0.0522	1.2671	1.3193	1.1922
2012-2013	24,222	5,513	29.47%	0.0676	1.2684	1.3360	1.0560
2011-2012	18,709	(4,269)	-18.58%	0.0681	1.2706	1.3386	0.8215
2010-2011	22,978	1,442	6.70%	0.1116	1.2901	1.4017	1.0107
2009-2010	21,536	(1,731)	-7.44%	0.1404	1.3126	1.4530	0.9472
2008-2009	23,267	540	2.38%	0.1978	1.3123	1.5101	1.0272
2007-2008	22,727	852	3.89%	0.1667	1.3467	1.5134	1.0055
2006-2007	21,875			0.1487	1.3648	1.5135	0.9679
Average			3.37%	0.1011	1.3301	1.4312	1.0807

Dependent Variable: WDKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:23
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 13 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.023303	0.002361	9.869817	0.0000
WHDDDAY	0.010107	7.56E-05	133.7373	0.0000
AR(1)	0.720398	0.175338	4.108627	0.0003
AR(2)	-0.674413	0.139871	-4.821675	0.0000
SIGMASQ	5.27E-05	1.44E-05	3.655916	0.0009

Root MSE	0.007262	R-squared	0.998618
Mean dependent var	0.229931	Adjusted R-squared	0.998440
S.D. dependent var	0.198113	S.E. of regression	0.007826
Akaike info criterion	-6.695142	Sum squared resid	0.001899
Schwarz criterion	-6.475209	Log likelihood	125.5126
Hannan-Quinn criter.	-6.618380	F-statistic	5599.821
Durbin-Watson stat	1.958334	Prob(F-statistic)	0.000000

Inverted AR Roots	.36+.74i	.36-.74i

Dependent Variable: WCDKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:21
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 8 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.289199	0.018994	15.22620	0.0000
WHDDDAY	0.032277	0.000820	39.37664	0.0000
AR(1)	0.302016	0.211936	1.425035	0.1638
SIGMASQ	0.002229	0.000616	3.618398	0.0010

Root MSE	0.047209	R-squared	0.994152
Mean dependent var	0.948686	Adjusted R-squared	0.993604
S.D. dependent var	0.626104	S.E. of regression	0.050072
Akaike info criterion	-3.043596	Sum squared resid	0.080232
Schwarz criterion	-2.867650	Log likelihood	58.78474
Hannan-Quinn criter.	-2.982186	F-statistic	1813.406
Durbin-Watson stat	1.869346	Prob(F-statistic)	0.000000

Inverted AR Roots	.30

Dependent Variable: CROOK60DKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:29
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 13 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.025604	0.003187	8.033353	0.0000
CROOKHDDAY	0.009949	0.000109	91.47806	0.0000
AR(1)	0.671462	0.167585	4.006697	0.0004
AR(2)	-0.576118	0.208172	-2.767511	0.0094
SIGMASQ	7.64E-05	2.23E-05	3.428628	0.0017

Root MSE	0.008739	R-squared	0.998127
Mean dependent var	0.243692	Adjusted R-squared	0.997885
S.D. dependent var	0.204783	S.E. of regression	0.009417
Akaike info criterion	-6.336294	Sum squared resid	0.002749
Schwarz criterion	-6.116361	Log likelihood	119.0533
Hannan-Quinn criter.	-6.259532	F-statistic	4129.672
Durbin-Watson stat	1.990344	Prob(F-statistic)	0.000000

Inverted AR Roots	.34-.68i	.34+.68i

Dependent Variable: CROOK70DKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:28
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.198033	0.027156	7.292350	0.0000
CROOKHDDAY	0.044392	0.000985	45.04877	0.0000
AR(1)	0.487218	0.213626	2.280709	0.0294
SIGMASQ	0.003635	0.001046	3.473723	0.0015

Root MSE	0.060288	R-squared	0.995372
Mean dependent var	1.171664	Adjusted R-squared	0.994939
S.D. dependent var	0.898821	S.E. of regression	0.063945
Akaike info criterion	-2.549618	Sum squared resid	0.130847
Schwarz criterion	-2.373672	Log likelihood	49.89313
Hannan-Quinn criter.	-2.488208	F-statistic	2294.376
Durbin-Watson stat	1.701550	Prob(F-statistic)	0.000000

Inverted AR Roots	.49

Dependent Variable: NORTH60DKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:32
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 12 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.017978	0.003948	4.553243	0.0001
NORTHHDDAY	0.009756	0.000127	76.93569	0.0000
AR(1)	0.506670	0.161455	3.138141	0.0036
SIGMASQ	6.49E-05	2.12E-05	3.055731	0.0045

Root MSE	0.008056	R-squared	0.998138
Mean dependent var	0.217644	Adjusted R-squared	0.997963
S.D. dependent var	0.189344	S.E. of regression	0.008545
Akaike info criterion	-6.574282	Sum squared resid	0.002336
Schwarz criterion	-6.398335	Log likelihood	122.3371
Hannan-Quinn criter.	-6.512872	F-statistic	5717.754
Durbin-Watson stat	1.617646	Prob(F-statistic)	0.000000

Inverted AR Roots .51

Dependent Variable: NORTH70DKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:31
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 31 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.230774	0.036008	6.409011	0.0000
NORTHHDDAY	0.042875	0.001225	35.00096	0.0000
AR(1)	0.686156	0.183062	3.748210	0.0007
SIGMASQ	0.002525	0.000800	3.156245	0.0035

Root MSE	0.050249	R-squared	0.996134
Mean dependent var	1.105564	Adjusted R-squared	0.995771
S.D. dependent var	0.819601	S.E. of regression	0.053297
Akaike info criterion	-2.903742	Sum squared resid	0.090900
Schwarz criterion	-2.727795	Log likelihood	56.26735
Hannan-Quinn criter.	-2.842332	F-statistic	2748.256
Durbin-Watson stat	1.783318	Prob(F-statistic)	0.000000

Inverted AR Roots .69

Dependent Variable: SOUTH60DKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:35
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 23 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.018548	0.003853	4.813680	0.0000
SOUTHHDDDAY	0.010404	0.000131	79.26205	0.0000
AR(1)	0.470893	0.215279	2.187357	0.0361
SIGMASQ	7.05E-05	2.14E-05	3.297467	0.0024

Root MSE	0.008394	R-squared	0.997838
Mean dependent var	0.207278	Adjusted R-squared	0.997635
S.D. dependent var	0.183093	S.E. of regression	0.008904
Akaike info criterion	-6.493329	Sum squared resid	0.002537
Schwarz criterion	-6.317382	Log likelihood	120.8799
Hannan-Quinn criter.	-6.431918	F-statistic	4922.928
Durbin-Watson stat	1.619584	Prob(F-statistic)	0.000000

Inverted AR Roots .47

Dependent Variable: SOUTH70DKDAY
Method: ARMA Maximum Likelihood (OPG - BHHH)
Date: 01/07/20 Time: 13:36
Sample: 2016M04 2019M03
Included observations: 36
Convergence achieved after 5 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.241524	0.018567	13.00839	0.0000
SOUTHHDDDAY	0.050995	0.001264	40.33207	0.0000
AR(1)	0.334246	0.185213	1.804662	0.0805
SIGMASQ	0.003075	0.001090	2.821472	0.0081

Root MSE	0.055451	R-squared	0.996051
Mean dependent var	1.166064	Adjusted R-squared	0.995681
S.D. dependent var	0.894947	S.E. of regression	0.058815
Akaike info criterion	-2.721125	Sum squared resid	0.110693
Schwarz criterion	-2.545178	Log likelihood	52.98025
Hannan-Quinn criter.	-2.659715	F-statistic	2690.628
Durbin-Watson stat	1.725060	Prob(F-statistic)	0.000000

Inverted AR Roots .33

GREAT PLAINS NATURAL GAS CO.
DEMAND ENTITLEMENT FILING 2019 - 2020 HEATING SEASON
DESIGN DAY - NOVEMBER 2019

	Customer Factors 1/			Design	No. of	Projected	Peak/	Projected Peak		Projected	Proposed	
Pipeline	Dk/day	Dk/DD	RSqr	HDD 2/	Customers 3/	Customers 4/	Customer	Day (dk) 5/	L&UA 6/	Design	Capacity	Reserve
VGT												
Crookston	0.04543	0.01391	0.99781	96	2,579	2,601	1.38079	3,593	25	3,618		
North 4	0.04637	0.01417	0.99787	91	7,222	7,278	1.33584	9,725	68	9,793		
Wahpeton	0.07191	0.01416	0.99780	91	2,268	2,303	1.36047	3,626	25	3,651		
Total VGT					12,069	12,182		16,944	118	17,062		
NNG	0.05107	0.01633	0.99758	83	12,050	12,134	1.40646	17,065	119	17,184		
Total					24,119	24,316		34,009	237	34,246	36,945	7.9%

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%.

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Number: G004/M-19-430 ☐Nonpublic ☒Public
Requested From: Great Plains Natural Gas Company Date of Request: 12/9/2019
Type of Inquiry: General Response Due: 12/19/2019

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us as well as the assigned analyst(s).
Assigned Analyst(s): Adam Heinen
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

Request Number: **2**
Topic: Reliability Concerns
Reference(s): October 15, 2019 Commission Order in Docket No. G004/M-18-454

Request:

Please provide the information required by the Commission in Ordering Point No. 3 in the above reference.

If this information has already been provided in initial petition or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).

Response:

- The pressure issue experienced in an outlying area near Fergus Falls on January 29, 2019 was related to a feed to a distribution regulator station.
  - Company personnel monitored and checked pressures manually throughout the night of January 29 and into the early morning of January 30 and there was no loss of service to customers.

Response Date: December 18, 2019
Response by: Travis Jacobson, Manager, Regulatory Affairs
Email Address: travis.jacobson@mdu.com
Phone Number: (701) 222-7855

   - Great Plains analyzed this area further and has replaced a 2” PVC main with a 4” main to address the pressure drop experienced in January 2019. The new main was placed into service on October 14, 2019.
- Pressure issues have not impacted service to the Company’s firm customers. As operating conditions deteriorate, Great Plains’ curtails interruptible customer consumption to maintain system integrity.
- Applicable to both NNG’s and Viking’s systems, impacts from the loss of a single compressor station are highly circumstantial. Factors such as location, system load, system receipts, operating conditions, time of day, advance notice, and other factors would affect the level of impact. Through normal course of business, transmission pipelines operated by entities such as NNG and Viking communicate outages and the resulting impact with shippers which guide operational decisions, such as curtailment events.
   - If circumstances narrowed in such a way to impact Great Plains’ distribution system and city gates, the result may be a loss of receipt pressure and lower volume. Once notified, Great Plains would make operational decisions to mitigate downstream impact, particularly to its firm customers.

Response Date: December 18, 2019
Response by: Travis Jacobson, Manager, Regulatory Affairs
Email Address: travis.jacobson@mdu.com
Phone Number: (701) 222-7855

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	G004/M-19-430	☐Nonpublic ☒Public
Requested From:	Great Plains Natural Gas Company	Date of Request: 9/24/2019
Type of Inquiry:	General	Response Due: 10/4/2019

Requested by: Adam Heinen
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **1**
Topic: Distribution Planning
Reference(s):

Request:

Please fully explain how the utility arrives at its weather assumption (*e.g.,* HDD, temperature) for distribution system planning purposes. As part of this explanation, please also identify the weather assumption used for each Town Border Station or City Gate on the utility's system.

If this information has already been provided in initial petition or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s).

Response:

Great Plains has historically modeled system changes necessary to accommodate new loads on the distribution system and monitored actual system pressures by border station during cold weather conditions to measure pressure drops in order to identify future necessary upgrades. The Company has recently employed distribution system planning models that will be updated and reviewed annually in order to analyze distribution capacity requirements. In that modeling, HDD values are calculated with the daily average temperature, to determine the simple average of the high and low temperatures for the coldest day in 30 years. The daily average is then subtracted from the HDD degree threshold 65 °F.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. G004/M-19-430

Dated this **27th** day of **January 2020**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Electronic Service	No	OFF_SL_19-430_M-19-430
Ryan	Barlow	ryan.barlow@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101214	Electronic Service	Yes	OFF_SL_19-430_M-19-430
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-430_M-19-430
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_19-430_M-19-430
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-430_M-19-430