November 29, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G004/M-17-521

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) regarding the Demand Entitlement Filing (Petition) and subsequent Informational Update Filing (Update) on Great Plains' 2017 Demand Entitlement submitted by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. (Great Plains or the Company).

The Department recommends that the Minnesota Public Utilities Commission (Commission) **accept** the Company's proposed level of demand entitlement and allow Great Plains to recover associated demand costs through the monthly Purchased Gas Adjustment (PGA) effective November 1, 2017. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ MICHAEL RYAN
Rates Analyst

/s/ SACHIN SHAH
Rates Analyst

MR/SS/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-17-521

I. SUMMARY OF THE UTILITY'S PROPOSAL

Pursuant to Minnesota Rules part 7825.2910, subpart 2, Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. (Great Plains or the Company), filed a petition on June 30, 2017 with the Minnesota Public Utilities Commission (Commission) to change the levels of demand for natural gas pipeline capacity (Petition). The Petition is the first in which the Company's South District and North District were combined based on the Commission's September 6, 2017 Order in Docket No. G004/GR-15-879.[1]

Great Plains filed an Informational Update Filing on November 1, 2017 (Update).

For the area of the Company's system that was previously known as the North District, Great Plains requested that the Commission accept its contracted 5,000 dekatherm (dth) per day of forward haul on the Viking system with receipt point of Emerson, and 10,000 dth per day of back haul capacity with a receipt point of Chisago, which when combined with an incremental 1,600 dth per day on Viking, is expected to be sufficient to meet the estimated peak-day demand. The capacity in this area for the 2017-2018 heating season will increase by 200 dth from the 2016-2017 heating season.

For the area of the Company's system that was previously known as the South District, Great Plains proposed to have the same volume of Northern Natural Gas Company's (NNG or Northern) capacity available as the prior year. However, Great Plains did not release 1,300 dekatherms per day of excess capacity as was done in prior years. The Company instead proposed to use the capacity to transport gas to the NNG/Viking Gas Transmission (VGT) interconnection at Chisago, and ultimately backhaul the gas to Minnesota cities including, but not limited to Vergas, Pelican Rapids, Fergus Falls, and Breckenridge. In other words, the Company proposed to use the NNG contract to serve customers that were historically in the North District.

[1] The Commission's Order states: "Regarding the consolidation of the rates in the North and South Districts: A. Great Plains shall implement a consolidated base cost of gas and purchased gas adjustment (PGA) beginning July 1, 2017. B. Great Plains shall consolidate its distribution rates according to its three-phase process implemented during the two years following implementation of the general rate increase resulting from this proceeding.

The Company projected a 5.23 percent reserve margin for the upcoming heating season.

Great Plains estimated that its proposal would cause an increase in rates for residential customers of $0.0066 per dekatherm or approximately $0.51 per year for customers assuming an annual usage of 77.9 dth.

Great Plains requested that the Commission allow recovery of the associated demand costs in the Company's monthly PGA for each district effective November 1, 2017.

II. PREVIOUS COMMISSION ORDER

In its June 8, 2017 Order in Docket No. G004/M-16-557 (16-557 Order), the Commission made the following disposition:

- Accepted the Company's proposed design-day method for the South District and the North District;
- Required Great Plains, in its future demand entitlement filings, to check the regression models it ultimately uses for autocorrelation, and correct the models if autocorrelation is present; and
- Approved Great Plains proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2016.

III. DEPARTMENT ANALYSIS

The Department's analysis of the Company's request includes the following areas:

- the proposed overall demand entitlement levels;
- the design-day requirements, including compliance with the Commission's 16-557 Order;
- the reserve margins; and
- the PGA cost recovery proposals.

A. PROPOSED OVERALL DEMAND ENTITLEMENT LEVELS

In its initial filing, the Company proposed to bid for 2,500 dth per day of incremental VGT pipeline via an open-season. The proposed capacity was meant to replace a contract of 1,400 dth per day that expired after the 2016-2017 heating season and to provide additional capacity for future years. Great Plains' Update stated that the bid for additional capacity was unsuccessful and that the Company instead secured an additional 1,600 dth per day from a marketer. The net increase of VGT capacity is 200 dth per day for the 2017-2018 heating season.

In regards to NNG capacity, Great Plains stated in its initial filing, as it has in prior years, that NNG's reallocation of TF-12B and TF-12V services are not known until the November update and that the changes are not significant normally. The reallocation changes are in accordance with NNG's tariff approved by the Federal Energy Regulatory Commission (FERC).[2] According to Great Plains in prior demand entitlement dockets, there is no deliverability difference between TF-12B and TF-12V services, but TF-12B service is less expensive than TF-12V service. Great Plains supplemented its Petition in its Update with the final reallocation of TF-12B and TF-12V demand entitlement changes and the associated rate and bill impacts. There was no change in the aggregate volume of NNG capacity year over year.

Table 1 below provides a comparison of the Company's current and proposed overall level of entitlements.

Table 1: A Comparison of Great Plains' Current and Proposed Entitlements

Pipeline	Current Entitlement (dth/day)	Proposed Entitlement (dth/day)	Change (dth/day)	Percent Change
VGT	16,400	16,600	200	1.22%
NNG	17,845	17,845	0	0.00%
Total	34,245	34,445	200	0.58%

As indicated in Table 1, the Company's proposal would result in an increase of 200 dth to the overall demand entitlement level compared to the current entitlement level. As discussed in further detail in Docket No. G004/M-15-645, Great Plains entered into a 10-year TFX annual contract with NNG for 2,000 dth/day effective November 1, 2015. In the Company's updated comments and compliance filing on October 29, 2015,[3] the Company stated that "although this amount of capacity exceeds current requirements, Great Plains believes it will require this amount of capacity in the near future." The 2017-2018 heating season is the first in which the Company has not released 1,300 dth per day of the capacity. Great Plains has instead explained in its initial filing and Update that the amount released in prior years will be used to deliver gas

[2] Under its federally approved tariff, NNG is allowed to adjust a utility's assigned level of contracted capacity based on the utility's usage of its NNG-based capacity over the previous five-month period (May through September).

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

to the NNG/VGT interconnection at Chisago and ultimately backhaul the gas to cities on what was historically considered the North District of its system.

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

B. DESIGN-DAY REQUIREMENTS

The Company 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.[4] 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.[5] Subsequently, Great Plains submitted a Compliance Filing on June 27, 2012 in Docket No. G004/M-10-1164. In that Compliance Filing, Great Plains provided additional discussion and analysis regarding its design-day method using different scenarios (i.e., as filed 36 months, 36 winter months only, 60 winter months only) as requested by the Department. The Department concluded that, "As noted above, despite these concerns, the Department believes that the Company's design-day analysis does not appear to produce unreasonable results."[6] The Commission agreed with the Department's conclusion that, while concerns about sample size and changing weather patterns still exist, the Company's design-day methodology was acceptable because its results were not unreasonable.

The Commission's *June 8, 2017 Order* in Docket No. G004/M-16-557 stated the following:

> Required Great Plains, in its future demand entitlement filings, to check the regression models it ultimately uses for

[4] The Department's concerns on this issue are discussed in detail in the following documents:

- the Department's July 2, 2008 *Comments* in Docket No. G004/M-07-1401;
- the Department's July 31, 2009 *Comments* in Docket No. G004/M-08-1306; and
- the Department's February 5, 2010 *Comments* in Docket No. G004/M-09-1262.

Commission Staff's concerns are discussed in detail in their September 9, 2010 *Briefing Papers*, which were contemporaneously submitted in each of these three dockets.

[5] *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.

[6] 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.

> autocorrelation, and correct the models if autocorrelation is present;

In its Petition Exhibit E, Great Plains stated the following:

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

Great Plains explained above that apart from the North and South residential rate classes (rate 60), the remaining firm general rate classes did not exhibit autocorrelation. However, in addition to the above rate classes, the Department notes that Great Plains' regression models [Crookston rate 60 (residential) and South rate 70 (firm general)] had autocorrelation present in the regression analysis.

In its Petition Exhibit E, Great Plains further stated the following:

> … An identical statistical method should be utilized for all rates; however, there are more rates that have evidence to support the absence of autocorrelation in their respective data sets so Great Plains believes that an OLS better fits the entirety of customer classes and should be the preferred statistical method rather than ARIMA [auto-regressive integrated moving average]. Great Plains also believes that any benefit that would come from purchasing statistical software for the sole purpose of correcting any autocorrelation issues would not exceed the coinciding cost. The inherent administrative burden that occurs with the

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

The Department appreciates Great Plains' discussion of autocorrelation described above. The Department has previously discussed the issue of autocorrelation and its potential impact and will not repeat that discussion here.[7] The Department does not advocate that Great Plains purchase statistical software for the sole purpose of addressing autocorrelation in its models and agrees with the Company that is not an appropriate cost for the company to pass on to its customers.

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[7] See the Department's *August 27, 2015 Comments* in Docket No. G004/M-15-645 at pages 4-5, and *November 10, 2016 Response Comments* in Docket No. G004/M-16-557 at page 8.

As noted above, Great Plains partially complied with the Commission's *June 8, 2017 Order* by checking its models for autocorrelation. However, Great Plains did not correct the models it identified (North and South Residential rate classes) for autocorrelation. The Department corrected the models for autocorrelation and makes the following observations:

- Great Plains' projected design-day was 32,733 dth/day and after correcting for correlation, the projected design-day changed to 32,763 or approximately by 30 dth which is not a significant change;

- Great Plains must plan for its design-day;

- Interstate pipeline capacity contracts are usually subscribed to for relatively long durations, for example 10 years. Great Plains recently signed a 10-year contract with NNG for an annual TFX service;[8] and

- Capacity is usually added in larger "chunks."

In addition, Great Plains has agreed to continue monitoring its data and models for autocorrelation. The Department appreciates Great Plains, agreement to monitor its data and models. As a result, based on all of the above information, the Department concludes that Great Plains' models can be used by Great Plains in planning for its design day.

Consistent with prior analyses presented by the Department in Docket Nos. G004/M-11-1075, G004/M-12-740, and G011/M-13-566, the Department used two methods to gauge the reasonableness of the Company's design-day amounts for Great Plains' consolidated system (previously known as the South District and the North District): 1) using data from the previous five heating seasons; and 2) using data from the heating season with the overall greatest peak sendout per firm customer that occurred before the previous five heating seasons.[9]

1. *Consolidated System (North and South District)*

The Department multiplied the peak sendout per firm customer for the 2014-2015 heating season of 1.2370 dth, which is the highest peak sendout per firm customer in the previous five heating seasons, by the expected number of firm customers for the 2017-2018 heating

[8] See the Department's August 31, 2016 Comments in Docket No. G004/M-15-645 (Docket 15-645) and the November 9, 2016 Supplemental Comments in Docket No. 15-645.

[9] The data used by the Department is taken from Exhibit D of the Company's Petition.

season of 23,997 to arrive at an estimated design-day amount of 29,684 dth/day. This amount is 3,049 dth/day less than the Company's proposed design-day level of 32,733 dth/day.

Thus, using the method based on the highest firm peak sendout data for the previous five heating seasons, Great Plains appears to have a sufficient level of entitlements for the 2017-2018 heating season for its system.

In past demand entitlement filings, the South District's 1995-1996 heating season represented the highest peak sendout per firm customer in the previous 21 heating seasons. Whereas for the North District, the 1999-2000 heating season represented the highest peak sendout per firm customer in the previous 21 heating seasons.

The Department also calculated an estimated design-day amount using data from the 1999-2000 heating season, which represents the highest peak sendout per firm customer in the previous 21 heating seasons for Great Plains' system. Specifically, the Department multiplied the peak sendout per firm customer for the 1999-2000 heating season of 1.5322 dth by the expected number of firm customers for the 2017-2018 heating season of 23,997 to arrive at an estimated design-day amount of 36,768 dth. This amount is 4,035 dth more than the Company's proposed design-day level of 32,733 dth/day.

Given the previous system configuration, the Department also calculated an estimated design-day amount using data from the 1995-1996 heating season, which represents the second highest peak sendout per firm customer in the previous 21 heating seasons for Great Plains' system. Specifically, the Department multiplied the peak sendout per firm customer for the 1995-1996 heating season of 1.5197 dth by the expected number of firm customers for the 2017-2018 heating season of 23,997 to arrive at an estimated design-day amount of 36,468 dth. This amount is 3,735 Dth more than the Company's proposed design-day level of 32,733 dth/day. The Department addresses this situation further in Section III.B.3 below.

2. Telemetry

Regarding the issue of telemetry, in its *January 9, 2014 Order* in Docket No. G004/M-12-740, the Commission had the following ordering point:

> 4. Telemetry
>
> a) Great Plains shall provide, in its next rate case, a full discussion and cost analysis showing the impact of requiring telemetry for all

> current interruptible customers and as a requirement for any future customer to receive interruptible service.

On September 30, 2015, Great Plains filed a *General Rate Petition* seeking Commission authorization to increase natural gas rates for utility service to Great Plains' Minnesota customers with a 2016 test-year in Docket No. G004/GR-15-879 (Docket 15-879). In its *General Rate Petition*, Volume 2, the Direct Testimony of Company Witness Patrick C. Darras stated the following[10]:

> **Q. Would you discuss the implementation of the automated meter reading (AMR) system at Great Plains?**
> A. Great Plains is currently installing automated meter reading (AMR) in all 18 communities and is expected to have the transition completed by the end of 2015. …
> Installing an AMR system will provide efficiencies along with cost savings. Great Plains anticipates direct savings of approximately $280,000 annually due to the elimination of meter readers, with these savings partially offset by the expenses with the new AMR system, primarily data collection costs, Great Plains has estimated full project payback in seven to eight years. Efficiencies gained will include: timeliness of billing, accurate reads, and the mobile completion of read transfers. The majority of the Great Plains AMR system will be fixed network which also provides a safer environment for employees as the need for being out in adverse weather conditions and traveling in general is substantially cut down.
> Implementation of AMR will also address the issue set forth in Docket No, G004/M-12-740, where Great Plains was ordered to provide, in its next rate case, a full discussion and cost analysis showing the impact of requiring telemetry for all current interruptible customers and as a requirement for any future customer to receive interruptible service **as AMR will apply to all interruptible customers and the Company will be able to differentiate between firm and non-firm use in developing its design day forecast.** The cost of the AMR system is estimated at $2.0 million with $1.8 million applicable to Minnesota gas operations.

[10] See the Direct Testimony of Patrick C. Darras at pages 6-7, in Docket 15-879 available here.

There does not appear to have been any further development on the Company's discussion above. During the April 6, 2016 pre-hearing conference in Docket 15-879, the Company's witness, Patrick C. Darras was waived from appearing at the evidentiary hearings.[11] On April 7, 2016 the Administrative Law Judge held evidentiary hearings in Docket 15-879. During the evidentiary hearings, Commission Staff had questions for Company Witness Travis R. Jacobson related to telemetry as follows:[12]

> Q Okay. On page 11 of your direct testimony you make reference to an automated meter reading program. You really did not -- or I did not see an explanation as to what that entailed. Could you kind of provide an explanation of exactly what that does entail?
> A You said on page 11?
> Q Yes.
> A And that relates to the -- rather than having an individual go around and walk house to house and read the meters, we would put an electronic signal on those meters, and they could either be picked up through a central collector or someone can drive down the street and pick those up. So in this reference, we had contracted with a third party to actually go read the meters, and what I was referencing here was that would be labor -- or a savings that we have included in the case, we'll no longer have that third-party contract.
> Q And does this, I guess, electronic meter reading capability, does that apply to all of your customer classes or just certain classes? I mean, is that, I guess, systemwide?
> A It would be systemwide as long as the capability is there. Maybe Bob would be able to answer if there are specific customers that would be excluded. It's intended to pick up the majority of the customers, which would be all your residential and your commercial. There may be some differences on the larger customers, and Bob will be able to answer that.

[11] See the Transcripts of April 6, 2016 in Docket 15-879 at pages 4-8, (edockets ID 20164-120216-01) available here.
[12] See the Transcripts of April 7, 2016 in Docket 15-879 at pages 46-49, (edockets ID 20164-120216-02) available here .

There did not appear to be any further questions on telemetry for Company Witness Robert Morman.[13]

On April 28, 2016, the Commission issued its Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724 regarding the demand entitlement petitions of Minnesota Energy Resources Corporation (MERC) for the 2015-2016 heating season (MERC Order). In the *April 28, 2016 MERC Order*, the Commission had the following Ordering point 13:

> Requested the Department to review and confirm how the other Minnesota natural gas utilities use metered daily interruptible data in the development of their Design Day requirements and provide a discussion explaining its conclusions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

With regards to the Commission's request in the *April 28, 2016 MERC Order*, Great Plains uses data for its Residential (rate 60) and Firm General (rate 70) classes only, when planning for its design day. Great Plains does not use interruptible data in the development of its design-day requirements. In addition, the Department has previously discussed Great Plains' use of calendar month data and the Company's new billing system.[14] Great Plains already has language regarding telemetering for its interruptible classes. For example, for the Small Interruptible Gas Sales Service for rate class N71 (see attached), the Company states the following:

> **Availability:**
>
> Service under this rate schedule is available to any interruptible general gas service customer, located in Great Plains' Minnesota North District Service Area (Breckenridge, Crookston, Fergus Falls, Pelican Rapids and Vergas), whose normal annual interruptible requirements are in excess of 1,000 dth but do not exceed 20,000 dth. Customer must satisfy Company of their ability and willingness to discontinue the use of said gas during period of

[13] See the Transcripts of April 7, 2016 in Docket 15-879 at pages 59-68, (edockets ID 20164-120216-02) available here .
[14] See the Department's November 10, 2016 Response Comments at pages 5-9 in Docket No. G004/M-16-557.

curtailment or interruption, by the use of standby facilities, or suffering plant shutdown. The rates herein are applicable only to customer's interruptible load. **Customer's firm natural gas requirements must be separately metered or specified in a firm service agreement. The firm service volumes are subject to available capacity. Customer's firm load shall be billed at Firm General Service Rate 70.** For interruptible purposes, the maximum daily firm requirement shall be set forth in the firm service agreement.

Conditions of Service:

5. METERING REQUIREMENTS – Remote data acquisition equipment (telemetering equipment) if required for daily measurement will be purchased and installed by the Company prior to the initiation of service hereunder. The cost of the equipment and its installation shall be paid for by the customer. Such contribution in aid, as adjusted for federal and state income taxes, must be paid prior to the installation of such equipment unless otherwise agreed to by the Company. Such equipment will be maintained by the Company and will remain the sole property of the Company. The Company may remove such equipment when service hereunder is terminated.

The customer may be required to provide and maintain, at no cost to Company: A 120 volt, 15 ampere, AC power supply, and an acceptable telephone service available at customer's meter location(s). The services listed above shall be continuous, accessible to the Company, and be provided by the customer at no cost to the Company. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.
Consultation between the customer and the Company regarding telemetering requirements shall occur prior to execution of the required service agreement. The telemetering requirement will

> be determined at the sole discretion of the Company based on customer requirements and location.
>
> The Company reserves the right to charge for each service call to investigate, repair, reprogram or reinstall the Company's telemetering equipment when the service call is the result of a failure or change in communication or power source services described above or damage to Company's equipment.

The tariff language appears to reflect adequate protection to the Company's firm customers. The Department also makes the following observations:

- As mentioned previously, Interstate pipeline capacity contracts are usually subscribed to for relatively long durations, for example 10 years. Great Plains recently signed a 10-year contract with NNG for an annual TFX service;[15] and

- Capacity is usually added in larger "chunks."

Given the long-term nature and size of interstate pipeline contracts, it is not clear to the Department how use of telemetering would "reduce costs." To the Department's knowledge, Great Plains does not use interruptible data in its design-day calculations and in any event, once (long-term) capacity is acquired for its residential and firm general class customers, that particular capacity cannot be reduced or increased on a permanent or annual basis. In addition, any changes would be subject to the prevailing conditions and availability on the particular interstate pipeline.

In summary, Great Plains appears to have minimally complied with the Commission's Order in Docket No. G004/M-12-740 by discussing its AMR system in its 2015 rate case. Further, the Department reviewed and confirmed that Great Plains does not use metered daily interruptible data in the development of their Design Day requirements and concludes that the Company's practice is appropriate.

3. Reasonableness of Great Plains' Design-Day Analyses

As noted above, when the all-time peak-day sendout is analyzed, it appears that Great Plains may not have sufficient capacity to serve firm customers on a Commission design-day.

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[15] See the Department's August 31, 2016 Comments in Docket No. G004/M-15-645 (Docket 15-645) and the November 9, 2016 Supplemental Comments in Docket No. 15-645.

However, in its 2010 demand entitlement proceeding, Great Plains stated that the peak-day use-per-customer figures during past heating seasons are no longer appropriate metrics because of the many changes (*e.g.,* the movement of firm customers to interruptible service, customer losses due to natural disasters, customer growth and losses, energy conservation) that have occurred since 1995, resulting in a steadily declining use per customer. In that same proceeding, the Department observed that, in general, Great Plains' assertions about changes in use per customer over time appear to be plausible and should be reflected in estimates of use per customer.

The extreme weather in the 2013-2014 heating season offers further insight into reliance on the all-time versus the 5-year peak-day sendout to evaluate the Company's design-day estimate. Great Plains experienced an outage in January 2014 when the TransCanada pipeline, which supplied gas to the VGT Company that serves Great Plains' customers in the North District, exploded. Further, Great Plains experienced some extremely cold weather during the months of January through March 2014.[16] Despite these challenges, the peak sendout during the 2013-2014 heating season of 27,693 dth was below Great Plains' estimated design-day of 29,433 dth.

In addition, Great Plains had an even greater peak sendout of 29,099 dth in the 2014-2015 heating season, which was also below Great Plains' estimated design-day of 31,124 dth.

As noted above, the Commission in its January 9, 2014 *Order* in Docket No. G004/M-13-566, accepted the Company's proposed design-day method for the South and North District, as recommended by the Department.

The Department recommends that the Commission accept the Company's same proposed design-day method for its system.

C. PROPOSED RESERVE MARGIN

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

> Great Plains shall reduce its reserve margin in Docket No. G-004/M-09-1262 to approximately five percent or explain why it is not reasonable to do so.[17]

[16] See pages 3 through 5 of the Company's August 29, 2014 Filing in Docket No. E,G999/AA-14-580.
[17] *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.

Table 2 below compares Great Plains' authorized and proposed reserve margins.

Table 2: Great Plains' Authorized Reserve Margins for the 2016-2017 Heating Season and Proposed Reserve Margins for the 2017-2018 Heating Season

2016-2017 Reserve Margin	Proposed Reserve Margin
5.70%	5.23%

Great Plains has kept its reserve margin near the 5 percent target that was established by the Commission in prior demand entitlements. The Department recommends that the Commission accept the Company's proposed reserve margin.

The Department notes that, in contrast to the electric utility industry, natural gas reserve margins are utility-specific rather than regionally specific, as more fully discussed in Attachment 4. However, given Minnesota's efforts to expand natural gas use in under- and unserved areas, and the increasing use of natural gas for electricity generation, there is a growing need to more closely examine reserve margins and to integrate natural gas supply planning with electric resource planning. In light of this recognition, the Department has issued information requests (see Attachment 5) and continues to follow-up with the utilities to ask for updated information. The Department will review those responses, in addition to information provided in the annual service quality and annual automatic adjustment reports, to ascertain, among other things, the number and timing of interruptions (curtailments) that may be occurring, and the causes of those curtailments, as a first step in assessing whether the demand entitlements procured, including reserve margins in place at those times, were sufficient or justified, and to continue monitoring the growing inter-relationship between the natural gas and electric industries.

D. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed above and in the Company's Petition and Update represent the demand entitlements for which Great Plains' firm customers would pay. In its Update, the Company used its July 2017 PGA to compare its proposed changes for its North District and South District.[18] Great Plains presented an analysis indicating that the Company's demand entitlement proposal would result in the following estimated annual rate impacts for customers in the North District:

[18] *See* Exhibit C of the Company's Petition. The exhibit is shown as North and South Districts due to the fact that not all components have been consolidated.

- an annual bill increase of $19.93 or approximately 3.94 percent, for the average residential customer consuming 77.9 dth annually; and
- an annual bill increase of $95.13 or approximately 3.60 percent, for the average firm general service customer consuming 434.4 dth annually.

Great Plains also presented an analysis indicating that the Company's demand entitlement proposal would result in the following estimated annual rate impacts for customers in the South District:

- an annual bill increase of $13.19 or approximately 2.79 percent, for the average residential customer consuming 77.9 dth annually; and
- an annual bill decrease of $57.56, or approximately 2.29 percent, for the average firm general service customer consuming 434.4 dth annually.

III. THE DEPARTMENT'S RECOMMENDATIONS

In the instan*t* Petition, Great Plains' analysis produces results that are acceptable for planning for the design-day. Therefore, the Department recommends that the Commission:

- accept the Company's proposed design-day method; and

- approve Great Plains proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2017.

/ja

Department Attachment 1
Docket No. G04/M-17-521
Great Plains Demand Entitlement Historical and Current Proposal

			As of 11/1/17			
Contract Type	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	2017-2018 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
VGT						
FT-A (12-month)	13,000	13,000	13,000	-		
FT-A (5-month)	2,700	3,400	2,000	(1,400)		
BP (5-month)	-	-	1,600	1,600		
Total VGT	**15,700**	**16,400**	**16,600**	**200**		
NNG						
TFX (12-month)*	2,000	2,000	700	(1,300)		
TFX (5-month)	6,200	6,200	6,200	-		
TF12B	4,604	5,421	4,854	(567)		
TF12V	2,931	2,114	2,681	567		
TF5	3,410	3,410	3,410	-		
TFX (Capacity Release)	(1,300)	(1,300)	-	1,300		
Total NNG	**17,845**	**17,845**	**17,845**	**-**		
Total Entitlement	**33,545**	**34,245**	**34,445**	**200**	**0.58%**	**0.41%**
Total Annual Transportation	**22,535**	**22,535**	**21,235**	**-**	**0.00%**	
Total Winter Only Transport	**11,010**	**11,710**	**13,210**	**200**	**1.71%**	
Percent of Winter Only Capacity	32.82%	34.19%	38.35%			

*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.
Source: Great Plains Exhibit B

Department Attachment 2
Docket No. G04/M-17-521
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)
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			0.55%			0.57%			0.11%		7.69%

	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)
2017-2018	unknown			0.0713	1.3640	1.4354	unknown
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			3.42%	0.1017	1.3193	1.4210	1.0549

*The Petition is the first in which the Company's South District and North District were combined based the ruling in Docket No. G004/GR-15-879. The Department combined the districts for comparison.
Source: Great Plains Exhibit D

Department Attachment 3
Docket No. G04/M-17-521
Great Plains Rate Impacts (North District)

General Service-Residential	Base Cost of Gas Change G004/MR-16-834 7/1/17	Last Demand Change 11/1/2016	July PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6063	$2.9476	$2.9569	$3.0604	17.42%	3.83%	3.50%	$0.1035
Demand Cost	$1.1890	$1.6360	$1.2611	$1.2677	6.62%	-22.51%	0.52%	$0.0066
Commodity Margin	$2.2596	$2.0262	$2.2735	$2.4192	7.06%	19.40%	6.41%	$0.1457
Total Cost of Gas	$6.0549	$6.6098	$6.4915	$6.7473	11.44%	2.08%	3.94%	$0.2558
Average Annual Use	78	78	78	78				
Average Annual Cost of Gas*	$471.68	$514.90	$505.69	$525.62	11.44%	2.08%	3.94%	$19.93

Firm General Service	Base Cost of Gas Change G004/MR-16-834 7/1/17	Last Demand Change 11/1/2016	July PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6063	$2.9476	$2.9569	$3.0604	17.42%	3.83%	3.50%	$0.1035
Demand Cost	$1.1890	$1.6360	$1.2611	$1.2677	6.62%	-22.51%	0.52%	$0.0066
Commodity Margin	$1.8487	$1.6571	$1.8626	$1.9715	6.64%	18.97%	5.85%	$0.1089
Total Cost of Gas	$5.6440	$6.2407	$6.0806	$6.2996	11.62%	0.94%	3.60%	$0.2190
Average Annual Use	434	434	434	434				
Average Annual Cost of Gas*	$2,451.75	$2,710.96	$2,641.43	$2,736.56	11.62%	0.94%	3.60%	$95.13

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	$0.1035	$0.0066	$0.2558	3.94%	$19.93
Firm General Service	$0.1035	$0.0066	$0.2190	3.60%	$95.13

* Average Annual Bill amount does not include customer charges.
Source: Great Plains Exhibit C

Department Attachment 3
Docket No. G04/M-17-521
Great Plains Rate Impacts (South District)

General Service-Residential	Base Cost of Gas Change G004/MR-16-834 7/1/17	Last Demand Change 11/1/2016	July PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6928	$3.0481	$3.0434	$3.0604	13.65%	0.40%	0.56%	$0.0170
Demand Cost	$1.1890	$1.2341	$1.2611	$1.2677	6.62%	2.72%	0.52%	$0.0066
Commodity Margin	$1.7592	$1.5743	$1.7731	$1.9188	9.07%	21.88%	8.22%	$0.1457
Total Cost of Gas	$5.6410	$5.8565	$6.0776	$6.2469	10.74%	6.67%	2.79%	$0.1693
Average Annual Use	78	78	78	78				
Average Annual Cost of Gas*	$439.43	$456.22	$473.45	$486.64	10.74%	6.67%	2.79%	$13.19

Firm General Service	Base Cost of Gas Change G004/MR-16-834 7/1/17	Last Demand Change 11/1/2016	July PGA 7/1/2017	Proposed Demand Changes 11/1/2017	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$2.6928	$3.0481	$3.0434	$3.0604	13.65%	0.40%	0.56%	$0.0170
Demand Cost	$1.1890	$1.2341	$1.2611	$1.2677	6.62%	2.72%	0.52%	$0.0066
Commodity Margin	$1.4707	$1.2827	$1.4846	$1.5935	8.35%	24.23%	7.34%	$0.1089
Total Cost of Gas	$5.3525	$5.5649	$5.7891	$5.9216	10.63%	6.41%	2.29%	$0.1325
Average Annual Use	434	434	434	434				
Average Annual Cost of Gas*	$2,325.13	$2,417.39	$2,514.80	$2,572.36	10.63%	6.41%	2.29%	$57.56

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	$0.0170	$0.0066	$0.1693	2.79%	$13.19
Firm General Service	$0.0170	$0.0066	$0.1325	2.29%	$57.56

***** Average Annual Bill amount does not include customer charges.
Source: Great Plains Exhibit C

Attachment 4 – Natural Gas Reserve Margins

Below is a brief summary of the differences between the electric and natural gas industries in terms of setting reserve requirements, and the factors impacting how natural gas reserve margins are developed.

A retail natural gas distribution utility acquires the product demanded by its customers through contracting with a natural gas transmission pipeline company for certain levels of product for specified time periods. A vertically integrated electricity provider supplies most of its own product (through owned generation or purchased power agreements), relying on the non-contractual market [for Minnesota, the Midcontinent Independent System Operator (MISO)] when consumption exceeds the levels planned or outages prevent supply at the planned levels. Thus, the electric industry structure requires interdependency among market participants, necessitating a common reserve margin to ensure balanced reliance on the larger system.

A major factor differentiating electricity and natural gas is a greater availability of storage options for natural gas as opposed to electricity. For example, if natural gas utilities are aware in advance of a cold snap in weather, they may use "line pack" as a way to "store" natural gas temporarily in the pipe for use during the cold snap. Further, when natural gas consumption exceeds the levels planned or pipelines are damaged causing a loss of supply, natural gas utilities may turn to their own storage resources, propane or liquefied natural gas peaking plant capabilities, curtail natural gas supplied to interruptible customers, or seek to procure capacity release opportunities, if any exist at that time and location.

Moreover, there is not an energy market or independent system operator to dispatch resources, as there is in the electric industry, in part because the natural gas systems are less interdependent on each other. Therefore, reserve margins on the natural gas system are utility-specific rather than regionally specific.

Natural gas reserve margins are not only utility-specific, but there may in effect be different levels of reserve margins in different places on the natural gas utility's system. That is, it may be misleading to consider one reserve margin as accurately reflecting the ability of the utility to supply natural gas. A utility may have what appears to be a reasonable overall reserve margin, but still experience curtailments at a certain Town Border Station (TBS) due to the inability to physically move available product to that location. Similarly, a utility may have what appears to be an unreasonably low reserve margin but still have large reserve margins at certain locations, with the flexibility (through a loop, for example) to move the excess gas to another location to avoid curtailments.

Appropriate natural gas reserve margins can be set using various methods. For instance, a natural gas reserve margin could be set equal to the output capability of a utility's propane or liquefied natural gas peaking plant because the function of that peaking plant is to provide product at times when demand exceeds pipeline supply. Therefore, it may be reasonable to set the reserve margin at the level of the peaking plant's capacity in order to ensure that peak demand is met should the peaking plant experience an outage. (This approach is called an "N minus one" approach.)

Natural gas utilities procure pipeline supply considering both minimum demand and peak demand. Minimum usage (minimum day load) on a winter day is estimated to ensure that base load gas acquired does not exceed the ability of the company to either use the gas for system load or to inject the gas into storage. The natural gas design-day calculation estimates the maximum firm demand anticipated under the most extreme weather conditions. The extent to which a utility procures entitlements in excess of its estimate of maximum firm demand may vary by utility depending on factors such as how much storage is in place, whether the utility has a peaking plant and the size of the plant, past experience, and expectation for load growth. Further, there may be a need to procure additional entitlements to meet design-day requirements, but the pipeline suppliers may not offer entitlements at the specific level needed. The excess amount procured could be considered, or proposed as, that utility's reserve margin, but the percentage represented by that reserve margin is not the result of a calculation; rather, it was dictated by the need to fulfill design-day needs. In other words, under certain circumstances a reserve margin may exceed the levels traditionally considered reasonable by the Commission, but be legitimately dictated by the availability of supply to meet the obligation to provide firm service.

At this time, the Commission should continue to determine the reasonableness of natural gas resources on a case-by-case basis.

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: G999/AA-16-524 ☐Nonpublic ☒Public
Requested From: All Regulated Natural Gas Utilities Date of Request: 11/8/2017
Type of Inquiry: General Response Due: 11/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us; michael.ryan@state.mn.us; angela.byrne@state.mn.us; stephen.rakow@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **22**
Topic: Distribution Planning
Reference(s): Department Information Request No. 18

Request:

Please provide the above reference, including any and all subparts, updated to the most recent date available.

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

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: G999/AA-16-524 ☐Nonpublic ☒Public
Requested From: All regulated gas utilities
Date of Request: 3/10/2017
Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

Request Number: **18**
Topic: Distribution Planning

Request:

A. Please provide a detailed discussion of how the utility plans, constructs, and maintains its distribution system. As part of this response, include a discussion about how the utility decides to add capacity or expand in to new, or growing, service territory.
B. Please provide daily throughput data, by each individual Town Border Station (TBS) or delivery point, on the utility's system since November 1, 2012. If available, please provide these data divided by firm, interruptible, and transport load. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
C. Please provide the number of interruption days, by TBS or delivery point, by month since November 2012. To the extent possible, please identify the number of interruption days that are non-weather related (*e.g.,* reliability purposes). Please also provide these data in Microsoft Excel format with all links, and formulae intact.
D. Please provide, on a daily basis since November 1, 2012 by TBS or delivery point, the maximum deliverable throughput by customer type. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
E. Please provide, by TBS or delivery point, on a daily basis since November 1, 2012 the percentage of deliverable capacity subscribed by the utility. If applicable, please identify other parties, and their percentages of subscribed capacity, at the TBS. Please also provide these data in Microsoft Excel format with all links, and formulae intact.
F. Please provide the following forecasted data, in Microsoft Excel format with all links and formulae intact, by TBS, or delivery point, for the next three heating seasons. If the utility expects daily fluctuation, please provide these data on a daily basis:
    a. Total utility throughput, if possible, divided by customer type (*i.e.*, firm, interruptible, transport); and
    b. Expected firm and total throughput available at the TBS or delivery point.
G. Please provide maps, by county, identifying the location (and name) of any, and all, TBSs or delivery points on the utility's system. If possible, please provide these maps in pdf and GIS executable formats.

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number: G999/AA-16-524 ☐Nonpublic ☒Public
Requested From: All regulated gas utilities
Date of Request: 3/10/2017
Response Due: 3/20/2017

Requested by: Adam Heinen/Michael Ryan/Angela Byrne/Steve Rakow
Email Address(es): adam.heinen@state.mn.us
Phone Number(s): 651-539-1825

a. Please identify, by county, on the maps in Part F, the location of any, and all, transmission assets on the utility's system.
b. If the utility has an affiliate transmission or intrastate pipeline utility, please also identify these assets on the maps provided in Part F, by county.

If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s).

To be completed by responder

Response Date:
Response by:
Email Address:
Phone Number:

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-17-521

Dated this 29th day of November 2017

/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_17-521_M-17-521
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_17-521_M-17-521
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_17-521_M-17-521
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_17-521_M-17-521
Brian	Meloy	brian.meloy@stinson.com	Stinson,Leonard, Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-521_M-17-521
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_17-521_M-17-521