

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Petitions for Recovery
of Certain Gas Costs

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In the Matter of the Petitions for Recovery
of Certain Gas Costs

In the Matter of the Petition by Great Plains
Natural Gas Co., a Division of Montana-
Dakota Utilities Co., for Approval of Rule
Variances to Recover High Natural Gas
Costs from February 2021

**FINDINGS OF FACT,
CONCLUSIONS OF LAW, AND
RECOMMENDATION**

This matter was assigned to Administrative Law Judges (ALJs) Jessica A. Palmer-Denig and Barbara J. Case to conduct a consolidated contested case hearing regarding whether Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co. (Great Plains) and other Gas Utilities¹ prudently incurred extraordinary costs for natural gas to serve their customers during the period of February 13-17, 2021 (the February Event). The Minnesota Public Utilities Commission (Commission) referred this matter pursuant to its Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing (Order for Hearing) issued on August 30, 2021,² in which it requested the preparation of a full report, based upon the consolidated case record.

The ALJs held an evidentiary hearing remotely by videoconference via Microsoft Teams on February 17-18 and 22, 2022. The parties filed post-hearing briefs on March 15, 2022, and responsive briefs on March 25, 2022. Additionally, Administrative Law Judge Christa L. Moseng held two remote public hearings on March 3, 2022. The hearing record closed on March 25, 2022.

Brian M. Meloy, Stinson LLP, appeared on behalf of Great Plains.

¹ In addition to Great Plains, the "Gas Utilities" include CenterPoint Energy (CenterPoint Energy), Northern States Power Company d/b/a Xcel Energy (Xcel Energy) and Minnesota Energy Resources Corporation (MERC).

² Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing at 7 (Aug. 30, 2021) (eDocket No. 20218-177548-04) (Order for Hearing).

Katherine Hinderlie and Richard Dornfeld appeared on behalf of the Department of Commerce, Division of Energy Resources (Department).

Joseph Meyer, Kristin K. Berkland and Peter Scholtz, appeared on behalf of the Office of the Minnesota Attorney General – Residential Utilities Division (OAG).

Brian Edstrom appeared on behalf of Citizens Utility Board of Minnesota (CUB).

Ryan Barlow, General Counsel, Jorge Alonso, James Worlobah, and Andrew Larson of the Commission appeared on behalf of Commission Staff.

STATEMENT OF ISSUES

The Commission identified the following issues in its Order for Hearing:³

A. Did the individual Gas Utilities act prudently before, during, and after the February Event, and are costs related to the February Event reasonable to recover from ratepayers?

B. Should the Commission disallow recovery of any costs for each utility?

C. If there are any disallowances for imprudent or unreasonable action, how should these costs be calculated?

D. The specific prudence questions raised so far, including but not limited to:

i. When and to what extent did Gas Utilities become aware of the potential for extreme weather during the February Event, and did they respond prudently and reasonably?

ii. Did the Gas Utilities have enough geographic diversity of gas supply and, if not, what was the potential financial impact?

iii. Should the Gas Utilities have had additional fixed-price contracts and, if so, what was the potential financial impact?

iv. Did the Gas Utilities maximize use of storage capacity and, if not, what was the potential financial impact?

v. Did the Gas Utilities maximize use of peaking capacity and, if not, what was the potential financial impact? Has Xcel's maintenance and

³ *Id.* at 7-8.

operation of its Wescott, Sibley, and Maplewood facilities resulted in financial impact?⁴

vi. Should the Gas Utilities have made more robust conservation efforts and, if so, what was the potential financial impact?

vii. Did the Gas Utilities timely and appropriately pursue recovery through insurance, federal regulatory actions, market rules, contract enforcement, and other available legal actions such that they have not missed deadlines or become barred from possible recovery on behalf of ratepayers and, if not, what is the potential financial impact?

viii. Are there any other issues or actions related to prudence and, if so, what is the potential financial impact?

E. Is it possible to assign extraordinary costs to customers or customer classes based on their consumption during the February Event and, if so, would it be reasonable to do so?⁵

SUMMARY OF RECOMMENDATION

The ALJs conclude that Great Plains acted prudently in connection with the February Event, that the extraordinary gas costs Great Plains incurred in order to serve its customers are recoverable, and that no disallowance related to the February Event is warranted.

Based on the testimony and other evidence in the record, the ALJs make the following:

FINDINGS OF FACT

I. Introduction

1. In February 2021, a winter weather event brought extremely cold weather to the southern United States, including the natural gas producing areas of Texas and Oklahoma. The cold temperatures caused significant disruption in the production and distribution of natural gas.

2. Natural gas is not price-regulated; rather it is a commodity, and its price is determined by the marketplace. As a result of the cold weather event in February 2021,

⁴ Great Plains does not have peaking capacity on its system and, therefore, this inquiry is not relevant to Great Plains.

⁵ The Commission noted that this list was not exhaustive, and the Commission requested the development of any other issues that could be relevant to its evaluation of the Gas Utilities actions or costs relating to the February Event. Order for Hearing at 8.

natural gas prices in some areas of the United States soared to levels never before previously seen.

3. In Minnesota, the four companies identified here as the Gas Utilities, provide natural gas service to nearly all Minnesota natural gas customers. These Gas Utilities are responsible for purchasing sufficient gas to meet customer demand and ensuring that their distribution systems remain functioning.

4. During February 13-17, 2021, which the Commission calls the “February Event,” the Gas Utilities maintained service to their customers, but incurred unprecedented levels of under-recovered costs for the purchase of natural gas in order to do so.

5. The Gas Utilities, including Great Plains, now seek to recover those costs. The Commission determined that a proceeding to assess the prudence of the Gas Utilities’ decisions in connection with the February Event was necessary as a part of that process.

II. Procedural Background

6. On August 30, 2021, the Commission issued an Order for Hearing, which, among other things, referred these matters to the Office of Administrative Hearings (OAH) for contested case proceedings.⁶

7. The Commission identified the parties to the contested case proceeding as CenterPoint, Xcel Energy, MERC, Great Plains, the Department, and OAG.⁷

8. The ALJs held a prehearing conference on September 13, 2021, and issued the First Prehearing Order on September 20, 2021.⁸ The First Prehearing Order established a procedural schedule, procedures for discovery, deadlines for prehearing filings, and procedures for the evidentiary hearing and briefing.⁹

9. The First Prehearing Order established the following schedule:

Event	Date
Utility Direct Testimony	October 22, 2021
Intervenor Direct Testimony	December 22, 2021
Rebuttal Testimony by all Parties	January 21, 2022

⁶ *Id.* at 7.

⁷ See First Prehearing Order at 3 (Sept. 20, 2021) (eDocket No. 20219-178082-02).

⁸ *Id.*

⁹ *Id.*

Surrebuttal Testimony by all Parties	February 11, 2022
All Parties File and Exchange Prehearing Filings	February 14, 2022
Evidentiary Hearing	February 17-18 and 22-23, 2022
Post-Hearing Briefs by All Parties and Proposed Findings Submitted by Utilities	March 15, 2022
Post-Hearing Reply Briefs and Revised Findings Submitted by All Parties (All Parties to Submit Redlines of Proposed Findings)	March 25, 2022
ALJ Report Issued	May 24, 2022
Arguments and Exceptions	June 3, 2022 ¹⁰

10. On October 1, 2021, CUB petitioned to intervene as a party.¹¹ The ALJs granted CUB's petition on October 12, 2021.¹²

11. On October 8, 2021, SLGI petitioned to intervene in MERC's Docket No. G011/CI-21-611.¹³ On October 20, 2021, SLGI's Petition to Intervene was granted as to the prudence review in MPUC Docket No. G-011/CI-21-611.¹⁴

12. On October 11, 2021, Minneapolis submitted a Petition to Intervene in MPUC Docket No. G008/M-21-138, stating that CenterPoint is the exclusive gas provider for Minneapolis and its residents.¹⁵ On October 20, 2021, Minneapolis's Petition to Intervene was granted as to the prudence review in MPUC Docket No. G008/M-21-138.¹⁶

¹⁰ *Id.* at 4.

¹¹ Petition to Intervene by The Citizens Utility Board of Minnesota (Oct. 1, 2021) (eDocket No. 202110-178489-01).

¹² Order Granting Petition to Intervene by The Citizens Utility Board of Minnesota (Oct. 12, 2021) (eDocket No. 202110-178734-03).

¹³ Petition to Intervene of Super Large Gas Intervenors (Oct. 8, 2021) (eDocket No. 202110-178613-03).

¹⁴ Order Granting in Part and Denying in Part the Petition to Intervene of the Super Large Gas Intervenors (Oct. 20, 2021) (eDocket No. 202110-178980-01) (SLGI's Petition to Intervene in MPUC Docket No. G-999/CI-21-135 was denied as that docket was not referred to the OAH for inclusion in the contested case proceeding.).

¹⁵ Petition to Intervene (Oct. 11, 2021) (eDocket No. 202110-178639-01).

¹⁶ Order Granting in Part and Denying in Part the Petition to Intervene of the City of Minneapolis (Oct. 20, 2021) (eDocket No. 202110-178978-04) (To the extent that Minneapolis's filings could be construed as a request to intervene in the remaining three dockets, Minneapolis's Petition to Intervene was denied.).

13. A Protective Order was issued on October 8, 2021, to address the handling of trade secret and nonpublic data.¹⁷ A Protective Order for Highly-Confidential Trade Secret Data was subsequently issued on October 11, 2021, and amended on October 26, 2021.¹⁸

14. On October 22, 2021, CenterPoint Energy, Xcel Energy, Great Plains, MERC, and the Joint Gas Utilities filed Direct Testimony.

15. On December 22, 2021, CUB, the Department, and the OAG filed Direct Testimony.

16. On January 21, 2022, CenterPoint Energy, Xcel Energy, Great Plains, MERC, and the Joint Gas Utilities filed Rebuttal Testimony.

17. On January 27, 2022, the Commission requested that the OAH hold two virtual public hearings in early March 2022 and provide a summary report.¹⁹

18. The ALJs held a second prehearing conference via Microsoft Teams on February 3, 2022.²⁰ They then issued the Second Prehearing Order on February 7, 2022, scheduling the evidentiary hearing to be held via Microsoft Teams on February 17, 18, 22, and 23, 2022, beginning at 9:30 a.m. each day, and requiring prehearing filings.²¹

19. On February 4, 2022, the Commission issued a Notice of Virtual Public Hearings, scheduling public hearings for March 3, 2022, at 1:00 p.m. and 6:00 p.m.²² On February 14, 2022, the Commission issued an addition to the February 4, 2022, Notice to inform the public that the Commission will also accept video comments as another method to participate in the virtual hearings.²³

20. On February 11, 2022, CUB, the Department, and the OAG filed Surrebuttal Testimony.

21. On February 14, 2022, the Joint Gas Utilities, CenterPoint Energy, Great Plains, Xcel Energy, MERC, the Department, CUB, and the OAG filed Written Summaries of Pre-Filed Testimony.

22. The ALJs held the evidentiary hearing on February 17, 18, and 22, 2022, via Microsoft Teams.

¹⁷ Protective Order (Oct. 8, 2021) (eDocket No. 202110-178630-02).

¹⁸ Protective Order for Highly-Confidential Trade Secret Data (Oct. 11, 2021) (eDocket No. 202110-178678-01); Amended Highly Confidential Trade Secret Protective Order (Oct. 26, 2021) (eDocket No. 202110-179189-04).

¹⁹ Request for the OAH to Hold Public Hearings (Jan. 27, 2022) (eDocket No. 20221-182049-03).

²⁰ Notice of Prehearing Conference (Jan. 31, 2022) (eDocket No. 20221-182273-02).

²¹ Second Prehearing Order (Feb. 7, 2022) (eDocket No. 20222-182513-04).

²² Notice of Virtual Public Hearings (Feb. 4, 2022) (eDocket No. 20222-182412-02).

²³ Addition to Notice of Virtual Public Hearings (Feb. 14, 2022) (eDocket No. 20222-182753-01).

23. On March 3, 2022, ALJ Christa L. Moseng held virtual public hearings via telephone and internet.

24. On March 15, 2022, all parties filed Initial Briefs and Proposed Findings of Fact.

25. On March 25, 2022, the parties filed Reply Briefs, redlines of the Proposed Findings of Fact, and CenterPoint Energy, Great Plains, Xcel Energy, and MERC filed responses to public comments.²⁴

III. Overview of U.S. Natural Gas Markets

26. The natural gas market differs in important and fundamental ways from the electric power market, reflecting the different structures of the two industries and the different products moving through those markets.²⁵ The electric power industry operates as a single, fully-integrated system, and the market operates in real-time, since electricity travels near the speed of light.²⁶ In contrast, the natural gas industry consists of multiple entities operating independently.²⁷ And while dynamic, the natural gas market is far more static than the electric market, particularly during strained operating conditions such as a winter storm.²⁸

27. The natural gas industry consists of: (1) producers that drill wells that bring raw natural gas to the surface; (2) midstream gathering and processing entities that carry the raw gas to treatment and processing facilities; (3) transmission pipelines which move dry (processed) gas and gas from storage to distant consuming markets; (4) storage providers which supply underground natural gas storage for system balancing and/or for later consumption; (5) local distribution companies (LDCs) that supply and deliver the natural gas actually consumed by utility customers to those customers; and (6) direct-connect end-users, such as power plants or large industrial users, which take natural gas service directly from the transmission pipelines rather than from an LDC.²⁹

28. In 1993, the Federal Energy Regulatory Commission (FERC) implemented Order No. 636.³⁰ Order No. 636 “unbundled” different aspects of the natural gas industry.³¹ Previously transmission pipelines bought and sold the bulk interstate gas, and

²⁴ The Administrative Law Judges requested that the parties use their best efforts to provide redlined findings of fact, in order to clearly highlight specific areas of dispute. The parties did so, but given the short timelines required in this matter and the volume of material to be reviewed, the Department and OAG noted that the failure to strike or revise certain facts did not constitute a stipulation or waiver as to that issue. The Administrative Law Judges appreciate the efforts of all of the parties to build the record for the Commission’s decision and have reviewed the parties’ final submissions and the entire record in light of the reservations asserted by the Department and OAG.

²⁵ Ex. 100 at 3, 15-16 (Smead Direct).

²⁶ *Id.* at 3, 15-16.

²⁷ *Id.* at 3-4.

²⁸ *Id.* at 16.

²⁹ *Id.* at 3-4; see also Ex. 506 at 3-4 (King Direct).

³⁰ Ex. 100 at 4 (Smead Direct).

³¹ *Id.*

thus delivered to their customers a “bundled” product consisting of gas, transmission, and storage; through unbundling, FERC instituted the current structure in which transmission pipelines strictly transport and store gas as contract carriers, while buyers and sellers purchase and sell gas separately, moving it through the transportation and storage services provided by the pipelines.³²

29. To serve the needs of firm customers, a natural gas LDC must contract with two different types of entities. First, the LDC contracts with transportation pipelines, who transport natural gas to the LDC’s service territory from the locations where it is produced, purchased and stored, under agreements and pursuant to tariffs regulated by FERC.³³ Natural gas is not produced within Minnesota, so the Gas Utilities rely on interstate pipelines to transport gas produced in other states to Minnesota.³⁴ Second, the LDC also contracts with suppliers of physical natural gas.³⁵

30. The trading of natural gas as a commodity is unregulated, but the United States natural gas market is subject to extensive reporting, observation, and analysis.³⁶ Natural gas prices “are driven by the competitive market forces of supply and demand.”³⁷

31. Many factors affect the competitive market pricing of natural gas, including weather forecasts, storage levels and activity, current and projected production levels, demand for liquefied natural gas (LNG) exports, pipeline constraints, pipeline tariff provisions and operational actions, and uncertainty of supply reliability.³⁸

32. The sale and purchase of natural gas takes place both through one-on-one bilateral negotiated transactions directly between counterparties and through open and transparent trading on organized and regulated exchanges, including the Intercontinental Exchange (ICE).³⁹

33. Physical gas is commonly traded at “market hubs” or “market centers,” collectively referred to as “trading hubs.” There are four trading hubs directly relevant to the Minnesota market: (1) Northern Natural Gas Company (NNG) Field/Market Demarcation (Demarc), which is the Kansas boundary between NNG’s supply-area system and the market system that serves Minnesota; (2) Ventura, Iowa (Ventura), where Northern Border Pipeline Company (Northern Border) and NNG intersect; (3) Emerson, Manitoba (Emerson), where TransCanada Pipeline feeds both Great Lakes Gas Transmission LP and Viking Gas Transmission Company (VGT); and (4) NiGas in the

³² *Id.*; see also Ex. 506 at 5 (King Direct).

³³ Ex. 506 at 6 (King Direct).

³⁴ *Id.* at 7.

³⁵ *Id.* at 6. Suppliers can either be producers of natural gas or marketers, who aggregate supply for commercial disposition. Ex. 100 at 5 (Smead Direct).

³⁶ *Id.* at 7; Ex. 506 at 5-6 (King Direct).

³⁷ Ex. 506 at 5 (King Direct).

³⁸ Ex. 100 at 20-23 (Smead Direct).

³⁹ *Id.* at 7; see also Ex. 506 at 24 (King Direct).

Chicago area (Chicago), where extensive storage connects with the pipelines serving Minnesota.⁴⁰

34. The physical delivery of gas from a seller to a buyer is typically arranged in one of three ways: (1) the daily physical spot market, where natural gas is bought and sold for delivery the next day (or in the case of a Friday, trades include nominations for flow on Saturday, Sunday, and Monday (and if Monday is a holiday, then Tuesday as well));⁴¹ (2) the monthly spot market, where gas is sold on monthly contracts for the upcoming month during a period called “bidweek” historically being completed sometime during the last week prior to the first day of the month the gas is intended to flow; and (3) long-term contracts, where gas supply is contracted under seasonal, annual, or multi-year deals.⁴² All of these different types of deals can be based on a fixed price or indexed based on a price reporting agency (PRA)⁴³ index.⁴⁴

35. Monthly transactions are for delivery of specified volumes, effective on the first of the month (and thus called “FOM”) and remain in effect each day of the upcoming month.⁴⁵ These deals typically occur during bidweek, which closes prior to the end of the preceding month. The bidweek FOM index is then published on or about the first business day of the month in which the trades will flow.⁴⁶ For February 2021 FOM deals, trading closed on January 28, 2021.⁴⁷

36. Because the major trading platforms are not open on the weekends or holidays, it is difficult for an LDC to find uncommitted supply during the weekend.⁴⁸ The intra-weekend market represents a less liquid bilateral market without the benefits of regular business day trading.⁴⁹

37. A subset of physical fixed price transactions (both monthly and daily) are reported on a voluntary basis to PRAs such as S&P Global Platts and Natural Gas Intelligence.⁵⁰ PRAs use this information to produce price indices, which are used for

⁴⁰ Ex. 100 at 5-6 (Smead Direct); see also Ex. 506 at 6-7 (King Direct).

⁴¹ Ex. 100 at 11, 14 (Smead Direct).

⁴² *Id.* at 11.

⁴³ In the wake of the Enron collapse, natural gas sales, futures transactions, the way these transactions are reported to PRAs, and the PRAs themselves became subject to a high degree of government oversight, through initiatives at FERC (such as FERC’s 2003 Policy Statement on Natural Gas and Electric Price Indices and FERC Order No. 704), the Commodity Futures Trading Commission (CFTC) and through major federal legislation (such as the Energy Policy Act of 2005, which provides broad enforcement power to both FERC and the CFTC), in order to ensure the integrity and reliability of price indices, so that they will be representative of the market. *Id.* at 8-9.

⁴⁴ *Id.* at 12.

⁴⁵ *Id.* at 14.

⁴⁶ *Id.* at 14-15.

⁴⁷ Evidentiary Hearing Tr. Vol. 2C at 26-27 (King).

⁴⁸ Ex. 100 at 18 (Smead Direct).

⁴⁹ Ex. 506 at 24-25 (King Direct).

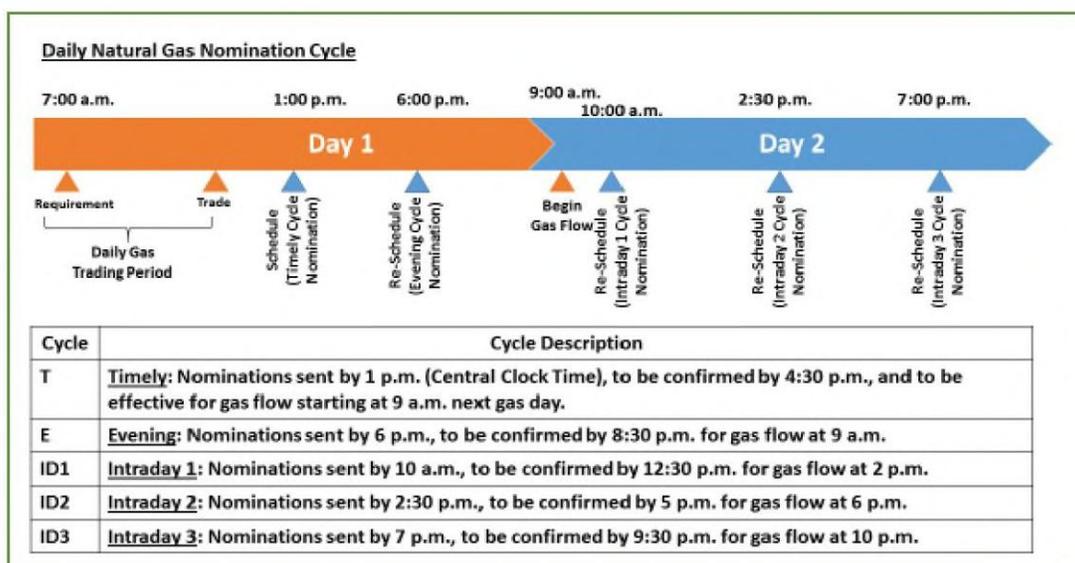
⁵⁰ Ex. 100 at 7 (Smead Direct).

index deals (i.e., deals that are settled based on a published index price).⁵¹ Fixed price deals that companies choose to report must be reported to PRAs by 3:00 p.m. central time. The PRAs pull the information into a database to create a weighted average (or some other mathematical midpoint).⁵²

38. Index deals are common in the natural gas industry—about 84 percent of the physical daily and monthly transactions in 2020 were done based on an index price.⁵³ Index deals are the dominant pricing structure, because these transactions share the risk of a changing market for the duration of the agreement.⁵⁴

39. Once physical natural gas is purchased, it needs to be scheduled (or nominated) to flow on the transportation pipelines. FERC requires transportation pipelines to incorporate nomination standards developed by the North American Energy Standards Board (NAESB) into their tariffs.⁵⁵ These standards set five different cycles upon which natural gas can be nominated — two during the day prior to the Gas Day, which begins at 9:00 a.m. central time, and three opportunities during the Gas Day.⁵⁶ The figure below illustrates these five nomination cycles. This pipeline nomination structure leaves limited ability to respond to changes during the day by buying and selling flowing gas supply.⁵⁷

NAESB Timeline⁵⁸



⁵¹ *Id.*; see also Ex. 506 at 75 (King Direct) (“Natural gas price indices are widely relied on to be representative of the price of gas at their respective locations.”).

⁵² Ex. 100 at 14 (Smead Direct).

⁵³ *Id.* at 7-8.

⁵⁴ *Id.* at 12.

⁵⁵ *Id.* at 16.

⁵⁶ *Id.* at 16-17.

⁵⁷ *Id.* at 16.

⁵⁸ Ex. 506 at 24, Figure 10 (King Direct).

40. When a transportation pipeline declares constrained operating conditions, which can include a “critical day,” “system overrun limitation,” or a “system underrun limitation,” LDCs and others flowing gas through pipelines can be exposed to substantial penalties for taking too much natural gas or for being out of balance between receipts and deliveries.⁵⁹ Those penalties can be up to three times the applicable daily spot price per unit on that day.⁶⁰

41. The restriction and penalty provisions of pipeline tariffs mean that during strained operating conditions the penalty rate for a pipeline imbalance is a multiple of the prevailing market price, making an imbalance penalty far more expensive than ensuring an adequate supply at the market price.⁶¹

42. The physical gas supply options available to the Joint Gas Utilities are: (1) baseload purchases; (2) storage assets; (3) swing supply; and (4) daily spot purchases.⁶²

43. Baseload purchases refer to fixed volumes of gas that flow every day for the term of the contract.⁶³ Baseload contracts are either monthly or longer-term contracts.⁶⁴ Typically, these baseload purchases are prices at FOM index price or a fixed price.⁶⁵

44. There are several different types of storage assets: (1) pipeline storage; (2) virtual marketer storage; and (3) utility-owned storage facilities. Pipeline storage contracts and virtual marketer storage contracts lay out the terms of how these storage assets can be used, including for example, maximum daily withdrawal limits.⁶⁶ Storage supplies are filled during the lower demand summer season for use during the higher demand winter season.⁶⁷ On a daily basis, storage provides an operational balancing tool to allow utilities to manage uncertainty and variability of load, including across weekends during which gas trading is limited.⁶⁸ Because regional storage around Minnesota is fully subscribed, the Gas Utilities cannot readily acquire additional storage without considerable effort and investment.⁶⁹

45. Swing supply refers to a commitment in advance for a supplier to bring an agreed upon volume of supply at the option or request of the buyer.⁷⁰ Swing supply provides assurance in advance that a quantity of physical gas supply will be available.⁷¹

⁵⁹ Ex. 100 at 18 (Smead Direct).

⁶⁰ *Id.* at 24.

⁶¹ *Id.* at 24-25.

⁶² *Id.* at 31.

⁶³ Ex. 506 at 21 (King Direct).

⁶⁴ *Id.*

⁶⁵ *Id.*

⁶⁶ *Id.*

⁶⁷ *Id.*

⁶⁸ *Id.*

⁶⁹ *Id.* at 21-22.

⁷⁰ *Id.* at 20.

⁷¹ *Id.*

Although swing supply provides quantity certainty, those deals are typically priced at a daily spot index.⁷²

46. Daily spot purchases refers to gas bought in the spot market for delivery the next day or the next few days (weekend or holiday period).⁷³ Daily spot purchases can be purchased for a negotiated fixed price or pricing can be based on the published daily market price index.⁷⁴

IV. Events Leading Up To February Event

47. In February 2021, cold weather across much of the United States led to increased demand for natural gas and, in some areas, supply disruptions.⁷⁵ An extreme rise in natural gas spot market prices ensued.⁷⁶ Minnesota's regulated gas utilities maintained continuous service to customers during this period, but some incurred unprecedented levels of costs purchasing gas on the daily spot market from February 13 through February 17, 2021, which the Commission has identified as the date range for the February Event.⁷⁷

48. During the February Event, the quantity of natural gas demanded increased considerably, as is typical with increasingly cold weather.⁷⁸ At the same time, production of natural gas decreased significantly because of freezing or power outages at wellheads and processing facilities.⁷⁹ The production decrease was regional.⁸⁰ The states further to the south, most notably Texas, had the biggest decrease in production because the electric and natural gas infrastructure in that region was not weatherized sufficiently to permit performance during long periods of extreme cold.⁸¹

49. In January 2021, the weather forecasts for February 2021 indicated that temperatures in Minnesota would be warmer than normal, as January 2021 had been.⁸²

50. On January 31, 2021, the revised weather forecast indicated that Minnesota and the rest of the Upper Midwest would be colder than normal in the month of February, but that temperatures would be normal or above normal in the south and south-central United States.⁸³ Thus, in late January, the Gas Utilities expected that while demand for

⁷² *Id.*

⁷³ Ex. 100 at 11, 14 (Smead Direct).

⁷⁴ *Id.* at 12.

⁷⁵ Order for Hearing at 1.

⁷⁶ *Id.*

⁷⁷ *Id.* at 1, 7 n. 7.

⁷⁸ Ex. 506 at 10 (King Direct).

⁷⁹ *Id.*

⁸⁰ *Id.*

⁸¹ *Id.*

⁸² Ex. 100 at 41-42 (Smead Direct).

⁸³ *Id.* at 42-43.

gas in Minnesota could be higher in February 2021, there was no indication that weather conditions would impact Minnesota's gas supplies from the southern United States.⁸⁴

51. The energy industry became aware of the potential for extreme weather at some point in early February,⁸⁵ but the extent of the extreme weather was not known early on in February.⁸⁶ The weather situation leading to the February Event continued to change and develop.⁸⁷

52. Both the February 8 and February 10 forecasts for Texas, relied on by the Electric Reliability Council of Texas (ERCOT), underestimated the extent of the cold weather experienced during the February Market Event.⁸⁸ The February 12 forecast was the first Texas weather forecast that captured the extent of the cold weather, and even that forecast had significant errors on certain days.⁸⁹ Notably, the February 12 forecast for Texas projected cold weather for a shorter duration and warmer temperatures than those that actually occurred.⁹⁰

53. On Thursday, February 4, 2021, NNG first called a system overrun limitation (SOL) and continued to call SOLs daily through February 17.⁹¹ When a SOL is in effect, the Gas Utilities may be assessed significant imbalance penalties by the pipeline.⁹²

54. On Friday, February 5, 2021, the weekend before the February Event began, Minnesota started to experience colder than normal temperatures.⁹³ Even with colder than normal temperatures in Minnesota, daily spot market gas prices at the supply points for Minnesota did not start to noticeably rise until February 10, 2021.⁹⁴

55. Also on February 5, 2021, the National Weather Service's 8- to 10-day outlook forecasted the probability of a cold weather event for the Midwest over the Presidents' Day weekend.⁹⁵

56. Predictions that the southern United States, including natural gas producing states of Texas and Oklahoma, would be faced with extreme weather did not occur until February 8, 2021.⁹⁶ On February 10 and 11, 2021, potential production freeze-offs were being reported by the trade presses.⁹⁷

⁸⁴ *Id.* at 42.

⁸⁵ Ex. 506 at 51 (King Direct).

⁸⁶ *Id.* at 53.

⁸⁷ *Id.*

⁸⁸ *Id.*

⁸⁹ *Id.*

⁹⁰ *Id.*

⁹¹ Ex. 801 at 15 (Cebulko Direct).

⁹² *Id.*

⁹³ *Id.* at 14.

⁹⁴ *Id.* at 18-19.

⁹⁵ *Id.* at 14.

⁹⁶ Ex.100 at 42 (Smead Direct).

⁹⁷ Ex. 801 at 16 (Cebulko Direct).

57. On Wednesday, February 10, as colder than normal weather was forecasted to persist in Minnesota, daily spot market gas prices began to rise for gas delivered on February 11.⁹⁸ At the end of the day on February 10, daily prices for deliveries on February 11 settled at \$6.61/Dth at Northern-Demarc and \$6.91/Dth at Northern-Ventura.⁹⁹

58. On Thursday, February 11, the colder than normal weather continued to impact daily spot market gas prices.¹⁰⁰ Daily index prices at the end of the day on February 11 for gas day February 12 settled at \$15.68/Dth at Northern-Demarc and \$15.42/Dth at Northern-Ventura.¹⁰¹ While prices increased from the prior day, these prices were still within the price ranges seen during prior cold weather events.¹⁰²

59. On the morning of Friday, February 12, 2021, the Gas Utilities purchased gas for delivery over the four-day Presidents' Day weekend (February 13-16) with forecasted continued colder than normal weather.¹⁰³ Typically, index priced gas purchases occur earlier in the trading day than fixed price transactions.¹⁰⁴ The Gas Utilities bought the entirety of their daily spot market purchases for the Presidents' Day weekend by the early morning on February 12.¹⁰⁵ Index trading that took place prior to 9:00 a.m. occurred, by design, without the benefit of any published prices.¹⁰⁶ When the Gas Utilities purchased index priced gas on the morning of February 12, they did not know what gas prices would ultimately be until later in the day.¹⁰⁷

60. On February 12, 2021, NNG posted a critical day notice effective from Saturday, February 13 through February 14.¹⁰⁸ NNG also posted critical day notices each morning from February 13-19.¹⁰⁹ A critical day is called when the operating condition of the pipeline system has severely deteriorated, and the integrity of the system is threatened.¹¹⁰

⁹⁸ Ex. 133 at 103 (Reed Direct); Ex. 203 at Sch. 2 at 23 (Derryberry Direct); Ex. 403 at 45-46 (Mead Direct).

⁹⁹ Ex. 203 at Sch. 2 at 23 (Derryberry Direct); Ex. 403 at 46 (Mead Direct).

¹⁰⁰ Ex. 133 at 75 (Reed Direct); Ex. 203 at Sch. 2 at 23 (Derryberry Direct); Ex. 403 at 47 (Mead Direct).

¹⁰¹ Ex. 203 at Sch. 2 at 23 (Derryberry Direct); Ex. 403 at 47 (Mead Direct); Ex. 133 at 75-76 (Reed Direct).

¹⁰² Ex. 133 at 75-76 (Reed Direct); see also Ex. 100 at 53-55, Sch. 7 (Smead Direct).

¹⁰³ Ex. 133 at 79 (Reed Direct); Ex. 405 at 46-47 (Mead Direct); Ex. 200 at 4 (Boughner Direct); Ex. 303 at 14 (Nieuwsma Direct).

¹⁰⁴ Ex. 506 at 58 (King Direct).

¹⁰⁵ *Id.* at 58-59. Both CenterPoint Energy and MERC purchased a portion of their spot market gas for the Presidents' Day weekend prior to the morning of February 12. Ex. 126 at 31-32 (Toys Direct); Ex. 403 at 46 (Mead Direct).

¹⁰⁶ Ex. 506 at 59 (King Direct).

¹⁰⁷ *Id.* at 60.

¹⁰⁸ Ex. 801 at 15 (Cebulko Direct).

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

V. Great Plains and its Actions in Connection with the February Event

A. Great Plains' Service Area

61. Great Plains provides retail natural gas service to 18 communities in Minnesota, serving approximately 22,500 customers.¹¹¹ Great Plains serves small urban communities within a largely rural service territory.¹¹² Great Plains serves its “northern” communities via gas delivered by VGT; these communities include Crookston, Vergas, Pelican Rapids, Fergus Falls, and Breckenridge. The “southern” communities Great Plains serves include Dawson, Boyd, Montevideo, Clarkfield, Granite Falls, Marshall, Wood Lake, Sacred Heart, Renville, Danube, Echo, Belview, and Redwood Falls, which receive gas delivered by NNG.¹¹³

62. Great Plains contracts for pipeline capacity on VGT and NNG in quantities sufficient to satisfy a design cold weather day based on its Gas Supply Group's analysis of the natural gas requirements of its retail natural gas sales customers for the upcoming heating season.¹¹⁴

B. Great Plains' Gas Supply Planning

63. Great Plains' primary objective in gas supply planning is to ensure the reliable delivery of natural gas supply to its retail customers.¹¹⁵ To mitigate risks associated with supply interruption or loss, Great Plains “diversifies its gas supply portfolio geographically, to the extent possible, to prevent against regional loss of gas supplies and contracts with proven suppliers who have demonstrated reliable performance.”¹¹⁶ To mitigate price risk, Great Plains contracts for gas at regionally diverse pricing hubs, utilizes a mix of pricing options, contracts for supply with multiple natural gas suppliers, and supplements its contracted natural gas supply with storage.¹¹⁷

64. Prior to each winter heating season, Great Plains issues a request for proposals (RFP) to natural gas suppliers for its winter base natural gas supply and swing gas supply.¹¹⁸ Great Plains evaluates supplier offers from the RFP process based on pricing, term, quantity, supply source diversity, and supplier diversity, to determine the most reliable and cost-effective portfolio of supply.¹¹⁹ In some instances, Great Plains

¹¹¹ Ex. 300 at 3 (Jacobson Direct). Great Plains also serves approximately 2,300 customers in Wahpeton, North Dakota. *Id.*

¹¹² *Id.*

¹¹³ Ex. 302 at 3 (Connell Direct).

¹¹⁴ *Id.* at 3-4.

¹¹⁵ *Id.* at 5.

¹¹⁶ *Id.*

¹¹⁷ *Id.* Great Plains uses supply resource optimization software to assist in supply planning and acquisition, which “has become a standard practice for gas utilities.” Ex. 306 at 14 (Amen Direct).

¹¹⁸ Ex. 302 at 6 (Connell Direct). Base supply is a quantity of gas the Company can receive on a daily basis throughout the month or throughout the entire heating season, regardless of weather conditions. Swing supply is a supply of natural gas a seller will guarantee to deliver, up to an agreed upon maximum quantity, as Great Plains requires it. *Id.*

¹¹⁹ *Id.*

seeks certain products from suppliers through its RFP process, but does not always receive responsive offers for the products it wishes to secure.¹²⁰

65. At the end of the RFP process, Great Plains typically has four types of supply within its supply portfolio: (1) Base Supply, (2) Storage, (3) Swing Supply, and (4) Day Gas.¹²¹

66. As noted above, Base Supply is a fixed quantity of gas that is supplied each day throughout the term of the agreement; the contracted volume may vary from month-to-month, but not day-to-day.¹²² Great Plains prices Base Supply agreements against either fixed price or FOM pricing index.¹²³

67. Storage Supply is gas delivered into Great Plains' storage account, typically during the summer, for use during the winter season; storage gas represents approximately seven percent of Great Plains' normalized supply requirement during the months of November through April.¹²⁴ Under its agreement with its storage provider, Great Plains may withdraw a contracted maximum of 4,640 Dth/day.¹²⁵ This 'Withdrawal Capacity' is reduced on a contractually defined schedule.¹²⁶

68. In total, Great Plains plans to obtain 75 percent of its supply through Base Supply and Storage.¹²⁷ Great Plains does not secure 100 percent of supply needs from Base Supply because "Great Plains and many utilities in the colder regions must limit the volume of gas taken under Base Supply contracts because regional utility demand may fall well below normal expectations when warmer than normal weather occurs. When demand falls below the contracted Base Supply, utilities risk failure to perform (breach of contract) against the Base Supply contracts if the utility has over contracted Base Supply."¹²⁸

69. A Swing Supply contract is an agreement between Great Plains and a seller, in which the seller guarantees delivery of up to an agreed-upon maximum quantity of gas directed by Great Plains. Swing supplies are priced against daily index prices and are subject to ratable weekend quantities – meaning that the quantity of gas must remain

¹²⁰ See *id.* at 9-10 (noting that although Great Plains sought swing gas at VGT-Emerson in both its 2020-2021 and 2021-2022 RFPs, no offers were received).

¹²¹ See Ex. 303 at 2-5 (Nieuwsma Direct).

¹²² *Id.* at 2.

¹²³ *Id.* Note also that "[i]ndex deals have become the dominant pricing structure, since neither counterparty is making a wager on the difference between the contract price and a changing market during the duration of the agreement. By agreeing to an index deal, neither party assumes the risk of market movement. For that reason, index deals are popular among LDCs, producers, and end-users. Fixed-price deals of any duration have declined in use." Ex. 100 at 12 (Smead Direct).

¹²⁴ Ex. 303 at 3 (Nieuwsma Direct).

¹²⁵ *Id.*

¹²⁶ *Id.*

¹²⁷ *Id.* at 5.

¹²⁸ *Id.*

static through all weekends (Saturday through Monday) and any holiday when the commodity market is closed.¹²⁹

70. Day Gas is a potential alternative to Swing Supply gas. When Great Plains' Base plus Storage Supply falls short of its total supply needs, Great Plains solicits offers for Day Gas before calling on Swing Supplies in an effort to determine if it can secure better pricing terms. However, because both Swing Supply and Day Gas are settled against an index, the key determinant is the adder (premium or discount) to the settled index price.¹³⁰

C. Events Leading up to February 2021

71. Based upon the weather forecasting described above, in late January, Great Plains expected that demand for gas in Minnesota could be higher in February 2021, but at that time, there was no indication that weather conditions would impact Minnesota's gas supplies from the southern United States.¹³¹

72. Going into February 2021, Great Plains held a cumulative Base Supply of 15,223 Dth/day, consisting of gas from three receipt locations or "trading hubs:"¹³²

- (1) Carlton, Minnesota (Carlton), where Great Lakes Pipeline delivers gas into NNG and to other market participants in Minnesota (1,723 Dth/day),
- (2) Emerson, Manitoba (Emerson), where TransCanada Pipeline feeds both Great Lakes and VGT (7,500 Dth/day), and
- (3) NNG Field/Market Demarcation (Demarc) the Kansas boundary between NNG's supply-area system and the market system that serves Minnesota (6,000 Dth/day).¹³³

73. With respect to Storage, Great Plains' storage withdrawal schedule called for a total of 60,875 Dth to be pulled out for the balance of the month (approximately 2,174 Dth/day). Great Plains began February with Storage inventory at 107,015 Dth. The targeted end-of-month balance was 46,140 Dth to provide storage security in March and April. Approximately 4,000 Dth/day was the daily limit of storage withdrawal. This value decreases linearly as each day's beginning balance declines.¹³⁴

¹²⁹ *Id.* at 3-4.

¹³⁰ *Id.* at 4-5.

¹³¹ Ex. 100 at 42 (Smead Direct).

¹³² Ex. 303 at 11 (Nieuwsma Direct). A receipt location is the location at which the party with title to gas inserts such gas into a pipeline. A delivery location is the location at which the party with title to gas takes gas from the pipeline. *Id.*

¹³³ *Id.*

¹³⁴ *Id.* at 12.

74. Great Plains had a total of 16,000 Dth/day of Swing Gas available to be called upon from Demarc (4,000 Dth/day) and Ventura/Marshall (12,000 Dth/day).¹³⁵

D. The February Event

75. Great Plains' storage supply plan called for Great Plains to deploy a daily average of 2,174 Dth/day throughout the month. The storage plan "was designed to deliver sufficient storage supplies to firm requirements customers and retain sufficient supplies in storage for unplanned peaking during the remaining winter months."¹³⁶ Great Plains stayed on this schedule for the first 10 days of February 2021. Beginning on February 11, Great Plains responded to decreasing temperatures by increasing its storage withdrawal quantities culminating with a maximized withdrawal of 3,944 Dth on February 14, 2021.¹³⁷

76. As the February Event approached, "Great Plains entered the morning of February 12, 2021, knowing that approximately 33,000 Dth/day of total supply was needed to meet customer demand for the holiday weekend of February 13-16, 2021. This quantity is much higher than normal demand due to expected cold weather; however, well within design conditions."¹³⁸

77. Weekends and holiday weekends are the least flexible and adaptable times in the natural gas market.¹³⁹ Large scale trading does not occur on weekends and holidays. Although buyers can purchase and transport gas intra-weekend, it is a less liquid bilateral market.¹⁴⁰

78. Because the February Event ran from Saturday, February 13, 2021, to Wednesday, February 16, 2021, and Monday, February 15 was a holiday (Presidents' Day), there are two business / trade dates of significance for gas flowing over the February Event: February 12 and 16. The Gas Utilities had to make spot purchases on Friday, February 12 for the Four-Day Period, and purchases on Tuesday, February 16 for Wednesday, February 17. Purchases for the Four-Day period of February 13-16 faced the ratable market requirement, meaning that on February 12, the Gas Utilities had to purchase the same amount of spot gas for February 13, 14, 15, and 16.¹⁴¹

79. As a result of these marketplace dynamics, all supply transactions Great Plains secured the morning of February 12 would be effective from February 13 through February 16, 2021, and there would be no opportunity for Great Plains to vary quantities of Swing Supplies or Day Gas purchases over this four-day period.¹⁴²

¹³⁵ *Id.*

¹³⁶ *Id.*

¹³⁷ *Id.*

¹³⁸ *Id.* at 14.

¹³⁹ Ex. 506 at 26 (King Direct).

¹⁴⁰ *Id.* at 24-25.

¹⁴¹ *Id.* at 25-26.

¹⁴² Ex. 303 at 14 (Nieuwsma Direct).

80. With respect to pricing, because Gas Daily/Demarc and Gas Daily/Ventura settlement prices had closed at greater than \$15/Dth for gas flowing on February 12, 2021, Great Plains elected to maximize its storage withdrawal for the four-day scheduling period (February 13-16), with a remaining supply requirement of approximately 13,800 Dth for the expected weekend peak.¹⁴³ To meet the remaining supply requirement, Great Plains had the option to either purchase Day Gas or call on its Swing Supply.¹⁴⁴

81. On February 12, Great Plains solicited offers for Day Gas and all offers, prior to 8:00 a.m. Central Time, were indexed-based and included a higher adder to index than did Great Plains' Swing Supply contract.¹⁴⁵ With no offers better than the contracted Swing Supply and with a call deadline in place, Great Plains called on its Swing Supply. At approximately 8:00 a.m., Great Plains decided to purchase an incremental 500 Dth/day for the four-day weekend.¹⁴⁶

82. Prior to the February Event, "the maximum daily index price for Gas Daily/Demarc was \$8.475 in March of 2019. Gas Daily/Demarc prices during the event settled with a multiple of twenty-seven times greater. Furthermore, Gas Daily/Demarc daily index prices have only settled above \$8 for four days since 2016."¹⁴⁷ The maximum Gas Daily index price for Ventura was \$67.455/Dth in December 2017 and Ventura Gas Daily prices have only settled above \$8/Dth for seven days since 2016.¹⁴⁸

83. When trading started on February 12, 2021, for flow dates February 13-16, 2021, Great Plains had documented the previous day settlement prices of \$15.68 and \$15.414 for Gas Daily/Demarc and Gas Daily/Ventura, respectively.¹⁴⁹ Further, "[p]rior to the contractually required Call time for Swing Supplies, there were no posted fixed price trades on ICE or fixed price offers available from Great Plains' counterparties."¹⁵⁰

84. In making its decisions to purchase sufficient supply on February 12 for the four-day Presidents' Day weekend, Great Plains had no reason is to believe that index

¹⁴³ *Id.* at 15.

¹⁴⁴ *Id.*

¹⁴⁵ *Id.* Great Plains was contractually obligated to call on Swing Supplies by 7:45 a.m. Central Time – well before the last deadline for pipeline nominations at 1:00 p.m. *Id.* at 15, n. 2.

¹⁴⁶ *Id.* at 15. As Mr. Nieuwsma testified, "[t]his decision was made because the Company had sufficient capacity, core demand exceeded delivered supply, and there was concern that NNG would be placing constraints to their system. Such constraints by a pipeline would leave shippers exposed to penalties if more gas was physically taken to meet customer demand than was scheduled. Sufficient capacity, demand exceeding supply and the likelihood of pipeline constraints made this purchase an appropriate action." *Id.* at 15-16.

¹⁴⁷ *Id.* at 17.

¹⁴⁸ *Id.* at 17-18; see also Ex. 506 at 15-16 (King Direct) (describing the price spike occurring over the New Years' holiday weekend in 2017-2018, in which gas prices at Ventura spiked to approximately \$65/Dth, a then record level).

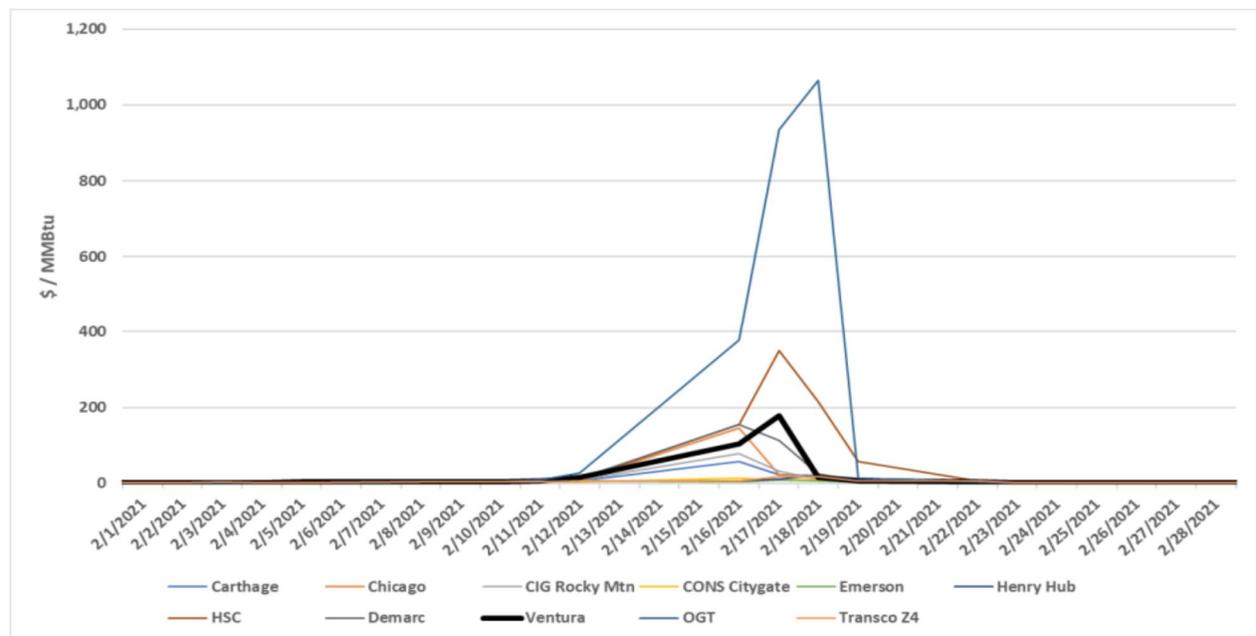
¹⁴⁹ Ex. 303 at 18 (Nieuwsma Direct).

¹⁵⁰ *Id.*

prices associated with its Swing Supply purchases could reach \$231.67/Dth and \$154.905/Dth at Demarc and Ventura, respectively.¹⁵¹

85. Based on historical pricing, “a reasonable actor on the morning of February 12 may have expected prices in the range of \$15-65/Dth, meaning a continuing increase of prices from the prior day with a ceiling expectation provided by a recent, similar event. A reasonable actor would also have understood the potential for prices to manifest outside of that range but would not have ascribed much serious possibility with those outcomes.”¹⁵² Further, “[t]he relevant index prices were not published until the late afternoon as is typical practice.”¹⁵³ As a result, Great Plains did not know where prices would settle at the time it made purchases prior to the long weekend.

86. Ultimately, gas prices spiked to prices far beyond any amounts previously experienced. Prices at Ventura (shown in bolded black below), the primary hub for the Gas Utilities, spiked to roughly \$155/MMBtu for the four-day period of February 13-16. The Northern Natural Gas (NNG) hubs of Demarc and Ventura encountered some of the highest prices, although there were hubs with even higher prices,¹⁵⁴ as shown below:¹⁵⁵



87. Prior to the February Event, the second highest price spike previously seen occurred over the New Year holiday weekend in 2017-18, and caused Ventura to spike to the then record high level of about \$65/Dth for the three-day delivery period of December 29-31 (2017-18 New Year Event).¹⁵⁶ The 2017-18 New Year Event was not

¹⁵¹ *Id.* at 17.

¹⁵² Ex. 506 at 60 (King Direct).

¹⁵³ *Id.*

¹⁵⁴ *Id.* at 11.

¹⁵⁵ *Id.* at 12.

¹⁵⁶ *Id.* at 15-16.

identical to the February Event, as it occurred earlier in the winter and did not involve natural gas production declines as significant as those seen in the February Event. Also, the actual price spike at Ventura, although record setting at the time, was significantly lower than the February Event (\$65/MMBtu versus \$155/MMBtu at Ventura). Further, that price spike was focused on the Ventura hub, and so was not as wide-reaching as the February Event.¹⁵⁷

88. As of February 16, the Gas Utilities knew that natural gas production failures had continued to increase considerably.¹⁵⁸ The U.S. Department of Energy's February 16 Situation Update (DOE Update) summarizes the circumstances over the previous weekend, including information the Gas Utilities would have known by that time.¹⁵⁹ Specifically, the DOE Update states that, "Extreme cold temperatures have led to sharp increases in gas demands to home heating and electricity generation across much of the Central U.S. At the same time, the cold has led to supply disruptions caused by well freeze-offs and natural gas processing plant outages in several producing areas in the U.S. South Central region (TX, OK, KS, LA, AR, MS, AL), which typically accounts for approximately 20-25% of total U.S. gas production."¹⁶⁰ Production outages represented "approximately 7% of total U.S. gas production."¹⁶¹ The DOE Update also states that, "Although production losses due to freeze-offs are temporary, output takes time to return to normal levels and the cumulative reduction over several days could be substantial."¹⁶²

89. By the time they needed to purchase gas on February 16, the Gas Utilities knew or reasonably should have known that ERCOT, SPP, and MISO were instituting controlled power outages and millions of customers were without power, including wellhead operations, processing facilities, and pipelines moving gas out of the Permian Basin.¹⁶³

VI. Standard of Review

90. Every rate made, demanded, or received by any public utility must be just and reasonable.¹⁶⁴

91. This proceeding addresses the reasonableness of the costs incurred by the Gas Utilities, and specific to this Report, whether Great Plains acted prudently before,

¹⁵⁷ *Id.* at 17.

¹⁵⁸ *Id.* at 62.

¹⁵⁹ *Id.* Although the DOE Update was not released until noon on Tuesday, February 16, it summarizes information that had developed over the long weekend and that a reasonable utility in the gas industry would have been aware of. Ex. 507 at 4 n.3 (King Surrebuttal).

¹⁶⁰ Ex. 506 at Sch. 11 at 7 (King Direct).

¹⁶¹ *Id.* at Sch. 11 at 2.

¹⁶² *Id.*

¹⁶³ *Id.* at Sch. 11; Ex. 100 at 49 (Smead Direct).

¹⁶⁴ Minn. Stat. § 216B.03 (2020).

during, and after the February Event, and whether the costs related to the February Event are reasonable to recover from ratepayers.¹⁶⁵

92. The term “prudence” means “skill and good judgment in the use of resources,” “caution or circumspection as to danger or risk,”¹⁶⁶ and “behavior that is careful and avoids risk.”¹⁶⁷

93. The parties to this proceeding generally agree on the parameters for determining prudence. Prudence is defined as reasonable action taken in good faith based on knowledge available at the time of the action or decision.¹⁶⁸ Actions taken in good faith are those taken without malicious intent,¹⁶⁹ exercising the care that a reasonable person would exercise under the same circumstances at the time the decision was made.¹⁷⁰

94. Prudence is not evaluated using the benefit of hindsight. Instead, the Gas Utilities’ actions and decisions must be judged on the basis of whether each action and decision was reasonable at the time, under all the circumstances, and based on the information that was or should have been known.¹⁷¹

¹⁶⁵ Order for Hearing at 7.

¹⁶⁶ *Prudence*, MERRIAM WEBSTER, <https://www.merriam-webster.com/dictionary/prudence>.

¹⁶⁷ *Prudence*, CAMBRIDGE DICTIONARY, <https://dictionary.cambridge.org/us/dictionary/english/prudence>.

¹⁶⁸ Ex. 506 at 28 (King Direct) (“I define prudence as reasonable action taken in good faith based on the knowledge available at the time.”); Ex. 103 at 13 (Honorable Direct) (noting that the prudence standard evaluates “whether the utility acted in good faith and reasonably, based upon the facts that it knew or should have known at the time, without the benefit of hindsight”); Ex. 819 at 13 (Nelson Surrebuttal) (noting the evaluation of prudence must “focus only on whether [t]he utilities exercised due care given what was known and knowable at the time of their actions”).

¹⁶⁹ See Evidentiary Hearing Tr. Vol. 2C at 25 (King) (“I had thought of it . . . as just meaning without malicious intent.”)

¹⁷⁰ Ex. 810 at 21 (Nelson Direct) (“The fact that a better outcome could have been reached in hindsight is not in itself permissible evidence in a prudence review; what matters is whether the utility acted reasonably based on the facts it ‘knew or should have known’ at the time. This is related to the concept of a ‘reasonable utility,’ which is expected to exercise ‘the care that a reasonable person would exercise under the same circumstances at the time the decision was made.’”).

¹⁷¹ Ex. 506 at 28 (King Direct) (Prudence must be assessed “based on the information the Gas Utilities had, or could reasonably have obtained, at the time of their actions and not the benefit of hindsight now available.”); Ex. 105 at 1 (Honorable Summary of Pre-Filed Testimony) (“It is my opinion that the Joint Gas Utilities have an obligation to act in good faith, based on the circumstances and facts known at the time, to obtain the necessary gas supplies to serve their retail customers at reasonable cost given the prevailing market at the time of the purchases. If they did so during the Winter Storm, the Joint Gas Utilities have acted in a prudent fashion and have incurred costs reasonably necessary to provide service to their customers.”); Ex. 600 at 17 (Lebens Direct) (The Commission “should focus as much as possible on evaluating the decisions that would have been prudent based on the information available at the time when those decisions were made.”); Ex. 104 at 4-5 (Honorable Rebuttal) (“This proceeding involves gas supply costs incurred by the Joint Gas Utilities to serve their customers in Minnesota during a recognized extreme weather event. Cold weather events create challenging and dynamic environments that require quick responses. Such circumstances should be considered as part of the overall prudence evaluation.”).

95. A determination of prudence must recognize that a utility may take a range of actions or decisions that are prudent.¹⁷² In many instances, there will not be one singular prudent action or decision but rather, a range of actions that are reasonable and prudent.¹⁷³

96. Prudence is applied to decisions.¹⁷⁴ Therefore, a prudence review is focused on an examination of specific decisions and whether the decisions were prudent or imprudent.¹⁷⁵

97. The burden to prove that its actions were prudent and that recovery of extraordinary costs is reasonable rests on Great Plains.¹⁷⁶

98. Utilities do not enjoy a presumption of prudence.¹⁷⁷ Doubts as to reasonableness are resolved in favor of the consumer.¹⁷⁸

VII. Determinations Already Made by the Commission

99. In its initial consideration of this matter, the Commission made certain determinations regarding the review in this proceeding.

100. The Commission defined in advance the relevant date range for consideration, identifying February 13-17, 2021, as the February Event.¹⁷⁹

101. The Commission determined that amounts below \$20/Dth could reasonably be considered “normal,” based on prices for natural gas before and after the February Event.¹⁸⁰ Therefore, the Commission concluded that “extraordinary” gas costs at issue in

¹⁷² Ex. 506 at 28 (King Direct) (“[I]n order for the actions of the Gas Utilities to be deemed prudent, they must fall within a range of reasonable action.”); Ex. 105 at 1 (Honorable Summary of Pre-Filed Testimony) (“Prudence is not evaluated on the basis of hindsight, and prudence determinations recognize that a utility may take a range of actions or decisions that are prudent.”); Ex. 819 at 19 (Nelson Surrebuttal) (agreeing that a range of utility decisions taken in response to a specific circumstance may be prudent).

¹⁷³ See Evidentiary Hearing Tr. Vol. 2C at 23 (King) (“Q. In order to be deemed prudent, the gas utilities’ actions must fall within a range of reasonable action. Correct? A. Yes. Q. Would you agree that a range of reasonable action includes more than one possible action? A. Yes”); Ex. 104 at 3 (Honorable Rebuttal) (“[T]he standard is clear that a range of reasonable utility management decisions made in response to specific circumstances may qualify as prudent – there is no single ‘right answer.’”).

¹⁷⁴ See Ex. 810 at 21 (Nelson Direct) (“The fact that a better outcome could have been reached in hindsight is not ... permissible evidence in a prudence review[.]”).

¹⁷⁵ Ex. 819 at 17 (Nelson Surrebuttal) (“[T]he focus of a prudence review is on specific decisions – not a vague ‘totality of decisions’ in which no specific decision can be identified as unreasonable.”).

¹⁷⁶ See Minn. Stat. § 216B.16, subd. 4 (2020).

¹⁷⁷ *In re a Comm’n Investigation into Xcel Energy’s Monticello Life-Cycle Management/Extender Power Uprate Project*, MPUC Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes at 12 (May 8, 2015).

¹⁷⁸ Minn. Stat. § 216B.03; see also Order for Hearing at 3 (“In incurring costs necessary to provide service, utilities are expected to act prudently to protect ratepayers from unreasonable risks.”).

¹⁷⁹ Order for Hearing at 11.

¹⁸⁰ *Id.*

this prudence review are the costs between a floor of \$20/Dth and the actual average daily price experienced by the Gas Utilities during the February Event.¹⁸¹

102. For Great Plains, the amount of extraordinary gas costs is \$8,827,249.¹⁸²

103. The Commission determined that certain customers should be exempted from cost recovery: (1) customers who currently qualify for assistance through the Low Income Home Energy Assistance Program (LIHEAP), or who qualified for such benefits at any time during the 2019-2020, 2020-2021, 2021-2022 or 2022-2023 heating seasons; and (2) customers with bills more than 60 and less than 120 days past due.¹⁸³

104. To the extent that the Great Plains is granted cost recovery, such recovery will be made over an extended period of time to reduce customer impacts using a volumetric charge with seasonally adjusted, stepped rates.¹⁸⁴

VIII. Undisputed Issues

105. As noted above, the Commission directed that certain issues be explored to determine the prudence of the Gas Utilities' actions related to the February Event.¹⁸⁵ The issues addressed in this section are undisputed, or largely so. The ALJs find that Great Plains met its burden to demonstrate the prudence of its actions as to these issues, as explained herein.

A. Geographic Diversity of Gas Supply

106. The Commission directed consideration of whether each utility had "enough geographic diversity of gas supply and, if not, what was the potential financial impact."¹⁸⁶

107. Geographic diversity of supply refers to a gas utility's ability to acquire gas supply from a variety of locations. The Gas Utilities' geographic diversity of supply is ultimately tied to the transportation arrangements they hold with pipelines. In any particular area, the pipelines that exist are the result of years of history based on the demand at major market centers and the production of natural gas from supply basins.¹⁸⁷ Reliance on a few pipeline hubs does not necessarily indicate a lack of geographic diversity.¹⁸⁸

¹⁸¹ *Id.* at 11-12.

¹⁸² *Id.* at 11.

¹⁸³ *Id.* at 16-17.

¹⁸⁴ *Id.* at 14. The Commission made an initial determination to permit recovery of prudently incurred costs over a 27-month period. The Commission is considering whether to extend that recovery over a longer period, but as of the date of this Recommendation had not made a decision to do so for Great Plains. See Notice of Comment Period (Jan. 28, 2022) (eDocket No. 20221-182103-02); see also Compliance Filing (Apr. 1, 2022) (eDocket No. 20224-184317-01).

¹⁸⁵ Order for Hearing at 7-8.

¹⁸⁶ *Id.* at 8.

¹⁸⁷ Ex. 506 at 42 (King Direct).

¹⁸⁸ *Id.* at 44.

108. As NNG is the key interstate pipeline serving the Minnesota Gas Utilities, a large quantity of gas supply purchases are tied to the NNG pricing hubs of Ventura and Demarc. Another major pipeline, VGT, is tied to the Emerson hub.¹⁸⁹

109. Great Plains seeks to ensure supply diversity through its annual RFP process, in which it seeks supply offers from gas receipt locations on the VGT and NNG pipelines that serve its customers. Great Plains obtained a geographically diverse supply of gas during the February Event, by contracting “for receipt capacity (locations where Great Plains receives gas for redelivery to its firm retail sales customers) on both VGT and NNG. Great Plains contracts for transmission capacity from geographically diverse locations to protect against a regional loss of supply.”¹⁹⁰

110. Great Plains’ ability to completely diversify its portfolio, however, depends “upon the Company’s ability to find trading partners with which to transact business at the desired locations and pricing structure.”¹⁹¹ With respect to the February Event:

Great Plains had purchased and scheduled gas from its contracted receipt locations of Emerson, Carlton, Marshall, Demarc, Ventura, and Ogden. In addition to scheduling gas from its Emerson receipt location, Great Plains also scheduled gas on VGT from the interconnecting point with NNG called Chisago. Emerson is where TransCanada feeds both Great Lakes Pipeline and VGT on the Canada/Minnesota Border in northwest Minnesota, Carlton is located in northeast Minnesota near the Wisconsin Border and is the intersection of Great Lakes Pipeline and NNG, Marshall is the intersection of Northern Border Pipeline and NNG near Marshall, Minnesota in southwest Minnesota, Demarc is the point of demarcation between NNG’s Field and Market Zones and is located in northeast Kansas, Ventura is the intersection of Northern Border Pipeline and NNG in north central Iowa, and Ogden is the point of receipt for Great Plains’ contracted storage and is located in central Iowa.¹⁹²

111. Great Plains also attempted to secure swing gas at VGT-Emerson for the 2020-2021 heating season, but received no offers in response to its RFP.¹⁹³ In general, “Great Plains’ experience trying to purchase gas from VGT-Emerson is that there are far fewer counterparties with which to transact day gas than there are at either NNG-Ventura or NNG-Demarc. Given the lack of a guaranteed swing supply offers at VGT-Emerson for the winter, Great Plains opted for a base supply purchase in a quantity which filled its downstream transportation capacity to ensure adequate supply on a peak day.”¹⁹⁴

¹⁸⁹ *Id.* at 43.

¹⁹⁰ Ex. 302 at 7 (Connell Direct).

¹⁹¹ *Id.* at 5-6.

¹⁹² *Id.* at 8-9.

¹⁹³ *Id.* at 9-10.

¹⁹⁴ *Id.* at 10-11; see also Ex. 506 at 50 (King Direct) (noting that it was not unreasonable for Great Plains to baseload at Emerson).

112. Further, Great Plains' ability to access other trading hubs is limited by its available transportation capacity because Great Plains does "not hold the upstream transportation necessary to access pricing at the Chicago hub" and "[i]f alternative pipeline capacity is not readily available, then causing it to be built would require an ongoing, fixed cost at a significant level."¹⁹⁵

113. Great Plains maintained sufficient geographic diversity of supply and its actions in this respect were prudent.

B. Fixed-Price Contracts

114. The Commission directed that this Report should consider whether each utility should "have had additional fixed-price contracts and, if so, what was the potential financial impact."¹⁹⁶

115. Daily spot gas can be bought at either a fixed-price or index price. In a fixed-price transaction, the buyer and seller agree upon a price for a certain amount of gas. Fixed-price transactions can occur at a variety of prices, depending on how volatile the spot market is, throughout a trading day.¹⁹⁷

116. For gas bought at an index price, the buyer and seller agree to a certain amount of gas priced at the midpoint of the culmination of that day's fixed-price trading.¹⁹⁸ The index price is calculated by data submitted from market actors to industry trade publications.¹⁹⁹

117. Index-priced transactions are generally offered earlier in the gas trading day. As a result of these dynamics, to make a fixed price purchase during the February Event, the Gas Utilities would have had to decide not to purchase their full gas quantities at index and instead to reserve a portion of their supply to purchase at fixed price later in the day.²⁰⁰

118. Therefore, "[b]uying at index ensures that the price paid will reflect the market midpoint for that day. Buying at a fixed-price represents a risk that the price paid could ultimately be higher or lower than the index."²⁰¹ It is not reasonable to expect the Gas Utilities to "systematically beat the index."²⁰²

¹⁹⁵ Ex. 506 at 48-49 (King Direct).

¹⁹⁶ Order for Hearing at 8.

¹⁹⁷ Ex. 506 at 74 (King Direct).

¹⁹⁸ *Id.* at 74-76.

¹⁹⁹ *Id.* at 74.

²⁰⁰ *Id.* at 75.

²⁰¹ *Id.* at 76.

²⁰² *Id.*

119. At 7:57 a.m. on Friday, February 12, 2021, Great Plains was offered a fixed priced swing purchase of \$85/Dth.²⁰³ Great Plains declined the offer because it was “higher than any price expected to settle under [its] index/contracts” and “the highest settlement price Great Plains had experienced in the past ten years occurred in December of 2017 when the Platt’s Gas Daily Ventura settled at \$67.455/[Dth].”²⁰⁴

120. In deciding whether to accept or reject the fixed price offer, Great Plains considered whether the offered price was “going to fall in the 50% greater than the eventual index settlement or will it be in the 50% of deals done under the settlement price”²⁰⁵

121. Based on Great Plains’ knowledge of gas pricing history, it determined “an offer of \$85/[Dth] seemed extremely excessive for weekend natural gas supply” and it decided to purchase at average index pricing.²⁰⁶

122. Great Plains could not have anticipated the extremely high pricing that occurred during the February Event. Expecting Great Plains to mitigate costs by securing additional fixed-price contracts in these circumstances would be unreasonable.²⁰⁷ Great Plains has established that it acted prudently regarding its decision not to purchase additional fixed price contracts.

C. Conservation Appeals

123. The Commission directed that the record should address whether the Gas Utilities should have made more robust conservation efforts and, if so, what was the potential financial impact.²⁰⁸ This issue relates to the question whether the utilities should have made voluntary conservation pleas to customers to reduce usage during the February Event.

124. A conservation plea is a request from the utility to customers to voluntarily reduce usage for a defined amount of time. These types of pleas are driven by a short-term event and distinguishable from general long-term efficiency and conservation measures, such as home weatherization and the installation of more efficient gas appliances.²⁰⁹ Conservation pleas have generally been limited to extraordinary circumstances.²¹⁰

²⁰³ Ex. 302 at 16 (Connell Direct).

²⁰⁴ *Id.* at 17.

²⁰⁵ *Id.*

²⁰⁶ *Id.*

²⁰⁷ The Department concurred that it would not have been reasonable to expect the utilities to beat the market by buying fixed price gas. See Ex. 506 at 76 (King Direct).

²⁰⁸ Order for Hearing at 8.

²⁰⁹ Ex. 506 at 101 (King Direct).

²¹⁰ *Id.* at 103.

125. As noted previously, Great Plains was required to lock in prices before 8:00 a.m. the morning of February 12 for the four-day Presidents' Day weekend. Following that, "customer demand reductions after the weekend natural gas supplies were purchased and scheduled would have required an offsetting reduction in storage utilization as that was the only scheduled supply that could be reduced to match demand over the weekend."²¹¹

126. "In order to reduce purchases, the Gas Utilities would have needed to estimate the impact of a conservation plea. While such an estimation could be made, there could be significant deviation from the actual impact which could have exposed the Gas Utilities to other issues such as imbalance penalties."²¹² The Gas Utilities should not "have reduced their spot market purchases during the February Event for planned conservation" as "conservation pleas are traditionally a last-resort reliability tool."²¹³

127. With respect to any potential excess gas Great Plains might have had if it had issued a conservation appeal, Great Plains could not reasonably have sold such gas, as Great Plains is not in the business of selling wholesale natural gas – it is a retail gas provider.²¹⁴

128. Accordingly, the record shows that more robust conservation efforts would not have mitigated the extraordinary gas costs incurred and prudence did not require Great Plains to issue a conservation plea.

D. Recovery from Other Sources

129. The Commission directed that this proceeding address whether the Gas Utilities timely and appropriately pursued "recovery through insurance, federal regulatory actions, market rules, contract enforcement, and other available legal actions such that they have not missed deadlines or become barred from possible recovery on behalf of ratepayers and, if not, what is the potential financial impact."²¹⁵

130. The Commission also directed the Gas Utilities to make quarterly compliance filings detailing their efforts to pursue recovery from other sources on behalf of ratepayers.

²¹¹ Ex. 302 at 13 (Connell Direct).

²¹² Ex. 506 at 102 (King Direct).

²¹³ *Id.* at 102-03; *see also* Ex. 100 at 36-37 (Smead Direct) ("The response to conservation appeals is the aggregate of a very large number of individual decisions, decisions that can change at any time, e.g., conserving during the day but then deciding to increase usage in the evening. In purchasing gas the morning before the Gas Day, it is essential to reliability that the LDC purchase enough supply for what its customers can take, not what it hopes they will take.").

²¹⁴ Ex. 302 at 13 (Connell Direct); *see also* Ex. 506 at 62 (King Direct) ("It was not unreasonable that the Gas Utilities did not attempt to make sales. The Gas Utilities are traditionally buyers of gas, and they have done zero to very little wholesale sales in the past. Additionally, the Gas Utilities were operating in an unprecedented pricing environment driven by extreme weather-induced widespread demand increase and production declines throughout a holiday weekend.").

²¹⁵ Order for Hearing at 8.

131. Great Plains has pursued relief and has reported recoveries in its quarterly reporting to the Commission.²¹⁶ At this time, Great Plains “is currently unaware of any potential wrongdoing or market manipulation but is aware there are investigations ongoing” and “continues to investigate whether any third parties are at fault” for the February Event.²¹⁷

132. Great Plains has not found “evidence of wrongdoing by any counterparties with whom [it] was transacting agreements during the February Weather Event. As is standard practice, Great Plains reviewed and reconciled all invoices against transaction confirmations and settlement prices.”²¹⁸

133. In filings with the Commission, the Department noted that “[t]he Gas Utilities unanimously state that they do not hold insurance policies that would be relevant to the Extraordinary Costs (or the conditions that caused them) and that such policies are generally unavailable. Because of the unprecedented nature of the February Event and the risk profile of such an event, the lack of insurance is not unexpected.”²¹⁹

134. Further, “FERC and other entities are investigating possible market manipulation related to the February Event price spike. Since announcing its investigation, FERC has indicated that its investigation has narrowed and is still ongoing. The outcome of any investigations will take more time to unfold.”²²⁰

135. The Department urges the Commission to withhold a determination of the prudence of Great Plains’ actions on this issue. It notes that facts related to the February Event and its causes remain unknown and are subject to ongoing investigation. The Department contends that the Commission should continue to review reporting from the Gas Utilities and make a determination of prudence regarding regulatory investigations, and the Gas Utilities’ efforts to pursue legal or contractual remedies, as more facts come to light.²²¹

136. The record in this proceeding establishes that Great Plains has complied with the Commission’s direction to investigate and pursue any available recoveries. Great Plains has reasonably evaluated, and continues to review, avenues to pursue recovery of extraordinary gas costs through insurance, federal regulatory actions, market rules, contract enforcement, and other available legal actions. There is no basis on this record to reject the prudence of Great Plains’ efforts on this issue. Therefore, the ALJs recommend that the Commission make an initial determination that Great Plains has appropriately sought recovery from other sources, but require ongoing compliance filings

²¹⁶ Ex. 300 at 15 (Jacobson Direct).

²¹⁷ *Id.*

²¹⁸ Ex. 303 at 18 (Nieuwsma Direct).

²¹⁹ Ex. 506 at 103 (King Direct).

²²⁰ *Id.* at 104.

²²¹ Department Initial Br. at 81-82 (Mar. 15, 2022) (eDocket No. 20223-183839-08).

from Great Plains and the other Gas Utilities. The Commission can take additional action at a later date based on further developments, if warranted.

E. Assignment of Extraordinary Costs to Customers or Customer Classes Based on Their Consumption During the February Event

137. The Commission directed that this proceeding address whether it is “possible to assign extraordinary costs to customers or customer classes based on their consumption during the February Event and, if so, would it be reasonable to do so?”²²²

138. Great Plains tracks usage based on its two classes for purposes of gas cost recovery: firm and interruptible sales.²²³ Consistent with its Purchased Gas Adjustment (PGA) mechanism in its Tariff, Great Plains has assigned the extraordinary gas costs from the February Event based on consumption for both classes during that period.²²⁴

139. Great Plains does not have actual consumption data for all customers in those sales classes for the February Event, and Great Plains would not be able to bill a specific cost assigned to each customer over the recovery period established by the Commission.²²⁵

140. The Department recognizes that it is not possible to assign extraordinary gas costs to customers or classes based on consumption during the February Event consumption, stating that “[t]he Gas Utilities explain that they lack the metering and billing infrastructure that would be necessary to conduct cost assignment and billing on such a granular level. This is not surprising given traditional utility metering, rate design, and billing.”²²⁶ The Department also contended that incremental cost causation improvements would need to be balanced against other ratemaking goals such as having rates that are simple, understandable, and affordable. The Department asserts that customer usage going forward can be a reasonable approximation of usage during the February Event.²²⁷

141. The Department recommended that the Gas Utilities track large customers to ensure that sales service customers during the February Event do not switch to transportation service to avoid paying for the extraordinary gas costs incurred.²²⁸ In response, Great Plains confirmed that it is monitoring such activity, but has not identified any customers that have switched to transportation service to avoid paying for extraordinary gas costs.²²⁹

²²² Order for Hearing at 8.

²²³ Ex. 300 at 16 (Jacobson Direct).

²²⁴ *Id.*

²²⁵ *Id.*

²²⁶ Ex. 506 at 107 (King Direct).

²²⁷ *Id.* at 108.

²²⁸ *Id.* at 108-09.

²²⁹ Ex. 301 at 9 (Jacobson Rebuttal).

142. The record shows that it is not possible to assign extraordinary gas costs to customers or customer classes based on their consumption during the February Event.

143. The Commission should require the Gas Utilities to continue to track large customers to ensure that sales service customers during the February Event do not switch to transportation service to avoid paying for the extraordinary gas costs.

IX. Disputed Issues

144. There are three disputed issues between Great Plains, the Department and the OAG.²³⁰ The Department contends that Great Plains was imprudent with regard to its actions related to gas purchases for February 17, 2021, by failing to: (1) maximize storage withdrawals; and (2) curtail interruptible customers.²³¹ The OAG contends the Gas Utilities, including Great Plains, failed to employ various financial hedging strategies that the OAG argues could have offset all or a portion of the extraordinary gas costs incurred during the February Event.²³²

A. Storage Utilization

(1) Great Plains' Use of Storage Gas During the February Event

145. Great Plains maintains storage capacity for deployment during the winter heating season. Storage is used to ensure reliable operations and maintain service to customers in the event of unexpected changes in demand or a sudden loss of supply and “[a] sudden increase of storage withdrawal can only be done if the Company has scheduled less than its daily withdrawal maximum.”²³³ Storage can also moderate the price of gas for ratepayers over the course of the heating season because storage is filled in the summer.²³⁴

146. Great Plains fully utilized its storage capacity for the four-day President's Day weekend.²³⁵ Great Plains then reduced its level of withdrawal on February 17.²³⁶ Great Plains maintains it did so “to 1) maintain supply flexibility in the event supplies were otherwise cut due to pipeline conditions and 2) to maintain the security of storage during

²³⁰ The Department and the OAG are the only parties to this proceeding that have taken a position with respect to whether the extraordinary gas costs incurred by Great Plains were prudently incurred. CUB filed testimony in this proceeding but did not take a position with respect to Great Plains' actions. See Ex. 810 at 6 (Nelson Direct) (“Strategen is not providing analysis or opinion on the prudence of Great Plains Natural Gas Co. and takes no position in regard to Great Plains in direct testimony.”).

²³¹ Ex. 507 at 6, 49 (King Surrebuttal).

²³² Ex. 600 at 43-44 (Lebens Direct).

²³³ Ex. 304 at 7 (Nieuwsma Rebuttal).

²³⁴ Ex. 506 at 21 (King Direct).

²³⁵ Ex. 309 at 2 (Nieuwsma Testimony Summary) (“Great Plains did withdraw 100% of its available storage capacity, to minimize exposure to daily gas market prices from February 13-16 because customer demand approached peak levels.”); see also Ex. 303 at 15 (Nieuwsma Direct). As the Department's witness Mr. King noted, “For the most part, the Gas Utilities maximized the use of their storage assets to mitigate spot gas costs.” Ex. 506 at 79 (King).

²³⁶ Ex. 309 at 2 (Nieuwsma Testimony Summary).

the forthcoming March and April,” and that “[a]djustments allowed Great Plains to stay near its targeted end-of-month inventory.”²³⁷

147. Great Plains has explained that: “Knowing that greater than planned storage withdrawals had taken place for the first sixteen days of February, that forecasted temperatures were expected to be warmer, demand decreased significantly from Sunday’s peak, and expecting index pricing to return to pre-event pricing, the storage withdrawal for Gas Day 17 was scheduled to the monthly planned 2,174 [Dth] withdrawal to begin working back to the monthly storage plan.”²³⁸

148. The Department contends that Great Plains failed to maximize its use of storage capacity on February 17, stating that Great Plains’ decision to “return its storage withdrawals to business-as-usual levels” for February 17 was unreasonable as there was no clear end to the price spike “meaning it could very well extend beyond the Four-Day Period and into February 17.”²³⁹ The Department calculated its recommended disallowance “by determining what [Great Plains] would have bought spot had it fully incorporated storage into its plan. That reduced spot amount is determined by grossing [Great Plains’] February 17 load forecast up for a 2% supply reserve margin and reducing that by baseload and available storage.”²⁴⁰ The Department asks that the Commission disallow \$439,450 of Great Plains’ gas costs, which is based on Great Plains’ jurisdictional allocation for Minnesota customers, related to its use of storage assets.²⁴¹

149. The Department correctly asserts that, by the time it was purchasing gas on February 16, Great Plains knew or should have known that the country and its energy markets were in the midst of an extraordinary event with the associated risk of spot gas prices remaining extremely high.²⁴² At the same time, Great Plains has articulated a variety of factors it considered in its gas planning decisions on February 16.

150. Great Plains notes that regional forecasted temperatures were moderating. Forecasted daily average temperatures for February 17 were 16 to 20 degrees warmer compared to the coldest day of the previous weekend,²⁴³ which Great Plains expected would lead to moderating pricing, based on its prior experience.²⁴⁴ Further, in Great Plains’ experience of the 2017-18 New Year Event prices spiked and moderated quickly:

²³⁷ Ex. 303 at 13 (Nieuwsma Direct).

²³⁸ Ex. 302 at 16 (Connell Direct).

²³⁹ Ex. 507 at 49-50 (King Surrebuttal).

²⁴⁰ Ex. 506 at 86 (King Direct).

²⁴¹ Department Initial Br. at 83 (Mar. 15, 2022) (eDocket No. 20223-183839-08). There was some disagreement about this amount. In its direct testimony, the Department recommended that \$546,810 be disallowed. *Id.* at 87, Sch. 5 at 1 (King Direct). However, Great Plains provided the jurisdictionally allocated amount in rebuttal testimony. Ex. 301 at 6 n.4 (Jacobson Rebuttal). The Department stated that it calculated the disallowance based on data provided by the Gas Utilities and did not dispute using the jurisdictional allocated amount. Department Initial Br. at 26 n. 98 (Mar. 15, 2022) (eDocket No. 20223-183839-08).

²⁴² Ex. 506 at 62-63 (King Direct).

²⁴³ Ex. 304 at 5 (Nieuwsma Rebuttal); see *also* Ex. 302 at 15-16 (Connell Direct).

²⁴⁴ Ex. 304 at 6 (Nieuwsma Rebuttal).

“Daily settlement prices for December 29-31, 2017 closed at \$67.455/MMBtu for Ventura. Prices for deliveries on January 1-2, 2018 dropped to \$5.23/MMBtu.”²⁴⁵

151. The Department points out that the facts surrounding the February Event were different from prior events in several respects and argues these differences suggested gas prices would take longer to rebound, including that the weather was colder farther south and the price spike covered the entire midcontinent market rather than solely the Ventura hub.²⁴⁶ In addition, the 2017-18 New Year Event did not have the same magnitude of natural gas production losses. For the February Event, “[e]xtreme cold temperatures ... led to sharp increases in gas demands for home heating and electricity generation across much of the Central U.S. At the same time, the cold ... led to supply disruptions caused by well freeze-offs and natural gas processing plant outages in several producing areas in the U.S. South Central region (TX, OK, KS, LA, AR, MS, AL), which typically accounts for approximately 20-25% of total U.S. gas production.”²⁴⁷ Production outages represented “approximately 7% of total U.S. gas production.”²⁴⁸

152. The Department asserts that Great Plains’ position that it expected prices to return to more normal levels and pre-event pricing,²⁴⁹ are contradicted by an email exchange in which Mr. Nieuwsma described Ventura pricing as a “risky price environment.”²⁵⁰ This email, in context, was part of a discussion about possible alternatives related to gas purchasing and does not support a determination that Great Plains should have used additional storage instead of purchasing gas. In the last email within the string, on the afternoon of February 16, Mr. Nieuwsma stated: “We had to purchase. Supply availability got really scarce just before 8:00 a.m. and our swing supply was our only option to take. Given that NNG has a Force Majeure in effect, we were at risk of losing supply cutting into our firm customers.”²⁵¹ He went on to state that he expected supply cuts and “erred on the side of keeping gas available for our firm customers.”²⁵² This email discussion illustrates the dynamic situation during the February Event and Great Plains’ focus on ensuring that it maintained a reliable supply for customers.

153. Great Plains also notes that one of the factors it considered in reducing its reliance on storage gas for February 17, is directly related to the issue of supply disruptions based on production decreases. Great Plains was concerned that supply disruptions could occur on February 17 based on the supply disruptions experienced February 13-16.²⁵³ During that time period, Great Plains’ “[s]torage was not available to make up for this loss of supply because Great Plains had maximized its withdrawals

²⁴⁵ *Id.*

²⁴⁶ Ex. 506 at 17 (King Direct).

²⁴⁷ *Id.* at Sch. 11 at 7.

²⁴⁸ *Id.* at Sch. 11 at 2.

²⁴⁹ See Ex. 304 at 5 (Nieuwsma Rebuttal); Ex. 302 at 16 (Connell Direct)),

²⁵⁰ Ex. 300 at Attach. A at 2 (Jacobson Direct).

²⁵¹ *Id.* at Attach. A at 1.

²⁵² *Id.*

²⁵³ Ex. 304 at 8-9 (Nieuwsma Rebuttal).

leaving the only alternative supply options to be found in the intra-day market or through shedding load. Fortunately, city gate scheduling imbalances were within pipeline tolerances and there were no punitive damages from these supply disruptions.”²⁵⁴ Great Plains determined that maintaining storage flexibility on February 17 would prevent the situation whereby a supply disruption occurred and no additional storage was available because gas supply purchases the day before already assumed maximum withdrawal.²⁵⁵

154. Further, Great Plains contends that its storage withdrawals had exceeded monthly planned withdrawals and there was a reasonable need to ensure supply flexibility for the remaining winter months for operational reasons.²⁵⁶

155. Storage is used operationally to maintain service to customers in the event of unexpected changes in demand or a sudden loss of supply and “[a] sudden increase of storage withdrawal can only be done if the Company has scheduled less than its daily withdrawal maximum.”²⁵⁷ “Storage is an essential swing supply that Great Plains relies on through the months of March and into April.”²⁵⁸ Storage gas is needed to “support deliverability throughout the entire winter period, not only at the days of peak delivery. To the extent that there is some variability between the cost of storage injections and withdrawals, it is an ancillary benefit of storage for a utility, not the primary function.”²⁵⁹

156. The Department agrees that Great Plains and the other utilities use storage for operational reasons unrelated to price²⁶⁰ and its witness, Mr. King, noted that storage is a “very valuable asset” and “provides an operational balancing tool to allow utilities to manage uncertainty and variability of load.”²⁶¹

157. At the same time, the Department contends that Great Plains’ decision to maintain storage gas as an asset for future needs was not reasonable in light of the extraordinary pricing situation and the fact that Great Plains’ maximization of storage on February 17 would not have had a great impact on its overall available storage volume for the rest of the heating season. The Department acknowledges that Great Plains had used a greater amount of storage gas than planned for February 2021, but asserts that it retained healthy amounts of gas in storage,²⁶² relying on the following chart:

²⁵⁴ *Id.* at 9.

²⁵⁵ *Id.* at 8.

²⁵⁶ *Id.* at 5, 8.

²⁵⁷ *Id.* at 7.

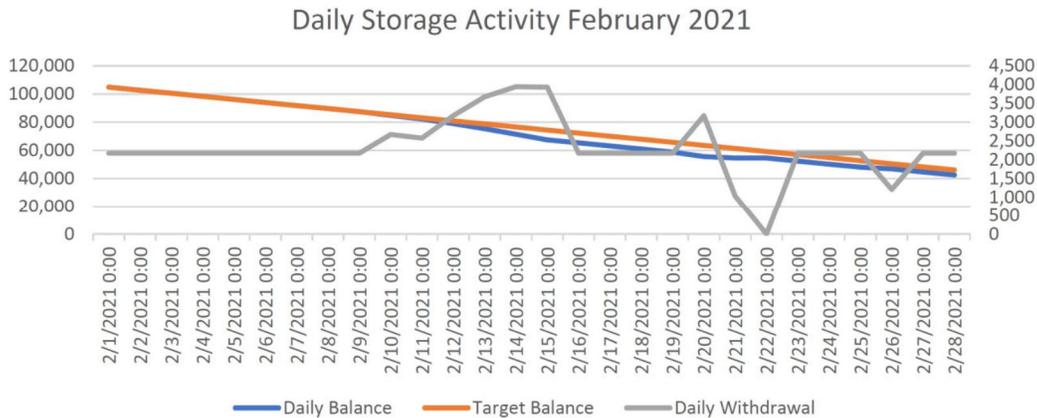
²⁵⁸ *Id.*

²⁵⁹ Ex. 305 at 22-23 (Porter Direct).

²⁶⁰ Evidentiary Hearing Tr. Vol. 2C at 67 (King).

²⁶¹ Ex. 506 at 21 (King Direct); *see also* Evidentiary Hearing Tr. Vol. 2C at 67 (King) (agreeing at the hearing that storage is used by Great Plains and other utilities for operational reasons – not simply price mitigation).

²⁶² Ex. 507 at 51 (King Surrebuttal).



158. At core, the Department’s argument requires a deviation from the standard used to determine prudence. That standard recognizes that utilities must make reasonable decisions based on all of the information available to them at the time and that there could be a range of prudent options at any time.²⁶³ Adopting the Department’s argument requires determining that there was only one prudent option: maximizing storage withdrawal to offset high prices. The Department’s position elevates consideration of the price of gas over all other considerations, given the extreme and unprecedented nature of the price spike. As noted above, however, prudence applies to decisions and not outcomes,²⁶⁴ meaning that the Commission must evaluate Great Plains’ decisions at the time they were made.

159. The Commission is investigating forward-looking strategies to address future price spike events. The Commission may wish to consider imposing a requirement that gas utilities maximize storage in some situations and the Commission could establish parameters to guide the utilities in doing so.

160. As of the February Event, however, Great Plains and the other utilities were required to make decisions based on rapidly developing information during an unprecedented and complex gas purchasing environment. Great Plains has established that it considered a variety of factors and made a reasonable decision among a range of potentially reasonable options.

161. The record establishes that Great Plains’ decision to revert to its storage withdrawal plan for February 17 was reasonable in light of the information available to Great Plains at the time the decision was made.²⁶⁵ As a result, Great Plains’ decision was prudent, and the Commission should not disallow recovery based on this issue.

²⁶³ Ex. 506 at 28 (King Direct); Ex. 103 at 13 (Honorable Direct); Ex. 819 at 13 (Nelson Surrebuttal).

²⁶⁴ Ex. 810 at 21 (Nelson Direct).

²⁶⁵ The ALJs note that the Department’s proposed disallowance is based on a Great Plains’ system wide basis, not only its Minnesota jurisdiction. If accepted, Mr. King’s proposed curtailment and storage disallowances should be approximately 80.4 percent of the total recommended disallowance of \$1,051,317 or approximately \$844,903. Ex. 301 at 6 (Jacobson Rebuttal); see also Evidentiary Hearing Tr. Vol. 2C at 68 (King).

(2) Supply Reserve Margin Issues

162. On a related issue, the Department contends that Great Plains' supply reserve margin for February 17 was unreasonable and resulted in excess extraordinary gas purchases.

163. The Department's expert, Mr. King opined that: "I accept the practice and reasonableness of planning for supply slightly in excess of expected load requirements in concept (a supply reserve margin) in light of the risks of under-supply. However, I testified that the amount of a supply reserve margin should be deliberately determined and explainable."²⁶⁶ With respect to Great Plains, Mr. King adopted a two percent supply reserve margin because "[Great Plains] itself procured supplies on February 14 that were 1.8% above its forecasted load."²⁶⁷

164. Mr. King stated, however: "I don't think there is a single universal number or source you could go to establish what a reasonable supply reserve margin is. And given that, I think the actual behaviors of the gas utilities in the specific event is really the best basis for what a reasonable supply reserve margin should be, as well as I do believe that it should be a fairly small figure all in all. And that's why I use the two percent."²⁶⁸ Therefore, Mr. King acknowledged that he offered no opinion that a supply reserve margin of two percent was a firm standard that utilities must use; instead, he confirmed that his use of a two percent supply reserve margin was based on the actual margin used by Great Plains the prior weekend.²⁶⁹

165. Great Plains' reserve margin for February 17 was 13 percent, based upon Great Plains' experience during the President's Day weekend.²⁷⁰ During that weekend, "actual load exceeded forecasted load by a daily range" of 9.6 to 16.6 percent, and Great Plains determined that it needed to ensure that it procured sufficient supply to meet its customers' need if demand increased to unexpected levels on February 17, as had happened during the foregoing weekend.²⁷¹

166. The Department contends that its proposed supply reserve margin of two percent is reasonable. However, Mr. King acknowledges that there is no "single figure for a supply reserve margin that can be universally applied," and that he "would not apply two percent outside of the specific facts and circumstances where it's being applied

²⁶⁶ Ex. 507 at 32 (King Surrebuttal).

²⁶⁷ *Id.* at 51.

²⁶⁸ Evidentiary Hearing Tr. Vol. 2C at 82 (King).

²⁶⁹ *Id.* at 63.

²⁷⁰ Ex. 304 at 14 (Nieuwsma Rebuttal).

²⁷¹ *Id.* at 12, 14. Note also that using a 10 percent reserve margin, Mr. King's proposed disallowance would drop to \$120,547, while the use of a 17 percent reserve margin would result in no disallowance. See *id.* at 13-14, Table 1, 2. The use of Great Plains' actual reserve margin of 13 percent would result in a *de minimis* disallowance of approximately \$344. See *id.* (showing the derivation of the disallowance by taking 13 percent of the load forecast (28,996 Dth x 13% = 3,769 Dth of reserves) and carrying the reserve margin through the calculation).

here.”²⁷² He testified that he was not recommending what a gas utility in Minnesota should use for a supply reserve margin on a permanent basis.²⁷³

167. Mr. King was asked about his selection of two percent as the recommended figure, in light of those other acknowledgements:

Q: “So I think, just to confirm that we’re understanding this right, you said that you don’t think there is a specific supply reserve margin that’s, you know, reasonable in all cases, but you have to fix something, right, in order to calculate a disallowance, which is what the Commission asked you to do. Is that a fair characterization of what you just said?”

A: “Yes.”²⁷⁴

168. A two percent supply reserve margin is not a recognized standard within the natural gas industry, and Mr. King’s opinion is based on the Gas Utilities’ experience over a very short period of time. Further, the Department’s position essentially requires the Commission to accept the two percent margin, notwithstanding all of the relevant circumstances, and then to require Great Plains to disprove that figure. That is not consistent with the framework of a prudence determination.

169. The Commission is reviewing this event in another docket to determine whether concerns about future price spikes warrant changes to the way gas utilities are regulated. The Commission may decide to adopt parameters governing gas utilities’ planning and use of supply reserve margins to plan for future events, but it had not adopted any guiding parameters as of the February Event.

170. Great Plains’ supply reserve margin was reasonable and is not a basis for disallowance.

B. Curtailment of Interruptible Customers

171. During the February Event, Great Plains provided gas service to all customers to meet their needs safely and without interruption. There were no physical constraints on Great Plains’ ability to serve its firm and interruptible customers.²⁷⁵

172. The Department evaluated whether the Gas Utilities could have reduced their spot purchases if they planned to economically curtail their interruptible customers

²⁷² Evidentiary Hearing Tr. Vol. 2C at 50 (King).

²⁷³ *Id.* at 63.

²⁷⁴ *Id.* at 82. Mr. King’s opinion and testimony on this point suggests a result-oriented approach to his selection of 2 percent as an appropriate supply reserve margin. To be clear, the Administrative Law Judges have not read the Commission’s charge to the parties or this tribunal as a directive to find and calculate disallowances. Rather, the Commission directed that this matter comprehensively consider the circumstances that arose during the February Event to determine if the Gas Utilities acted prudently, and if not, to identify the basis upon which disallowances should be calculated.

²⁷⁵ Ex. 300 at 4 (Jacobson Direct).

during the February Event.²⁷⁶ Mr. King concluded that “I do not believe it was unreasonable for the Gas Utilities (other than Xcel) to not plan on curtailing on February 12.”²⁷⁷ Mr. King based this conclusion on the fact the Gas Utilities have not previously curtailed interruptible customers for economic reasons and “the magnitude of the price spike was unprecedented and not fully understood by the Gas Utilities on February 12 when they made their purchasing decisions for the Four-Day Period.”²⁷⁸ The record supports this conclusion.

173. The Department asserts, however, that the scope of the price spike became clear by February 16, and that Great Plains should have reduced its spot purchases of natural gas on February 16 based on planned curtailments on February 17.²⁷⁹ The Department originally recommended a disallowance for Great Plains of \$504,507 calculated based on an “assumed volume of planned curtailments equal to 50% of the usage of curtailment” on February 17.²⁸⁰ The Department has revised its proposed disallowance figure to \$405,453.²⁸¹

174. Minn. Stat. § 216B.05, subd. 1 (2020), provides that “[e]very public utility shall file with the commission schedules showing all rates, tolls, tariffs, and charges which it has established and which are in force at the time for any service performed by it within the state.”

175. Great Plains’ tariff related to interruptible customers specifies the circumstances under which a customer may be curtailed. The tariff authorizes curtailments only for operational reasons, based on whether the Company has the physical ability to serve firm customers.²⁸²

176. Both Great Plains’ small and large interruptible service tariffs provide the following language:

PRIORITY OF SERVICE – Deliveries of gas under this schedule shall be subject at all times to the prior demands of customers served on the Company’s firm gas service rates. Customers taking service hereunder agree that the Company, without prior notice, shall have the right to curtail or to interrupt whenever, in Company’s sole judgment, it may be necessary to do so to protect the interest of its customers whose capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity

²⁷⁶ Ex. 506 at 96-101 (King Direct).

²⁷⁷ *Id.* at 99.

²⁷⁸ *Id.*; see also Ex. 300 at 13 (Jacobson Direct) (“Great Plains has never curtailed any customers in the past for economic reasons, nor has the Commission authorized Great Plains to take such action.”).

²⁷⁹ Ex. 506 at 100 (King Direct).

²⁸⁰ *Id.* at 100-01.

²⁸¹ Department Initial Br. at 82 (Mar. 15, 2022) (eDocket No. 20223-183839-08).

²⁸² Ex. 300 at 8-9 (Jacobson Direct).

shall be accomplished in accordance with the provisions of the General Terms and Conditions, Section 6, Paragraph V.17.²⁸³

177. Great Plains' tariff further provides:

PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY –
Priority of Service from Highest to Lowest:

- (a) Priority 1 – Firm sales services.
- (b) Priority 2 – Small interruptible sales and small interruptible transportation services at the maximum rate on a pro rata basis.
- (c) Priority 3 – Large interruptible sales and large interruptible transportation services at the maximum rate on a pro rata basis.
- (d) Priority 4 – Large interruptible transportation services at less than the maximum rate from the highest rate to the lowest rate and on a pro rata basis where equal rates are applicable among customers.
- (e) Priority 5 – Interruptible grain drying sales services.

Company shall have the right, in its sole discretion, to deviate from the above schedule when necessary for system operational reasons and if following the above schedule would cause an interruption in service to a customer who is not contributing to an operational problem on Company system.

Company reserves the right to provide service to customers with lower priority while service to higher priority customers is being curtailed due to restrictions at a given delivery or receipt point. When such restrictions are eliminated, Company will reinstate sales and/or transportation of gas according to each customer's original priority.²⁸⁴

178. There is no dispute that the Gas Utilities have not historically curtailed customers based on price considerations. Notwithstanding that, the Department states that Great Plains could have “economically” curtailed interruptible customers on

²⁸³ Original Sheet No. 5-30 (Small Interruptible Gas Sales Service Rate 71), *available at* <https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas71.pdf>; Original Sheet No. 5-50 (Large Interruptible Gas Sales Service Rate 85) *available at* <https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas85.pdf>.

²⁸⁴ Original Sheet No. 6-23 to 6-24 (Priority of Service and Allocation of Capacity), *available at* <https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGeneralTermsConditions.pdf>.

February 17 on an “ad hoc” basis without the need to “fully develop a permanent program to do so.”²⁸⁵

179. When customers accept service under Great Plains’ interruptible tariff, they are made aware that they can be curtailed for operational reasons and such “interruption is a condition of the service provided and is reflected in the service pricing.”²⁸⁶ It is important for interruptible customers to know before electing interruptible service from a utility the circumstances under which they could be curtailed, and a utility’s tariff provides that notice.²⁸⁷

180. According to Great Plains, “[a]n economic curtailment is not a condition of service for the Company’s interruptible natural gas customers. An economic curtailment has never been called by the Company and there are no predefined rules that would apply that have been shared with customers informing them of the circumstances under which they may be interrupted.”²⁸⁸

181. The Department argues that Great Plains has broad authority to curtail customers under its tariffs. To the contrary, the tariffs at issue clearly do not contain any terms allowing curtailment due to cost. There is no set price at which an economic curtailment could be triggered, and no parameters in the tariff to govern the prioritization of customers in the event of an economic curtailment. The tariff’s terms evidence that their purpose is to allow curtailment because of capacity, deficiencies in supply and other system operational reasons, without regard to price.²⁸⁹

182. The Department relies on an email exchange in which employees of Great Plains discussed the tariff language and determined an argument could be made that the pricing event related to operational concerns.²⁹⁰ This email exchange reflects that Great Plains’ employees were attempting to explore all avenues to respond to pricing concerns and to ensure that they had capacity to serve all of their customers. It does not reflect consultations with counsel or show a final decision was made that Great Plains could economically curtail customers with interruptible service.

183. The record does not establish that Great Plains’ tariffs permit it to curtail customers for economic reasons. As with other issues in these dockets, the Commission may wish to consider reviewing tariff language for the Gas Utilities to determine whether provisions related to curtailments should be adjusted and how. As of the time of the

²⁸⁵ Ex. 507 at 6 (King Surrebuttal).

²⁸⁶ Ex. 301 at 3 (Jacobson Rebuttal).

²⁸⁷ Evidentiary Hearing Tr. Vol. 2C at 61-62 (King).

²⁸⁸ Ex. 301 at 3 (Jacobson Rebuttal).

²⁸⁹ The Department has suggested that Great Plains could have revised its Tariff in light of the February Event, such as by making a miscellaneous filing with the Commission. Department Reply Br. at 17 (Mar. 25, 2022) (eDocket No. 20223-184159-06). While this could theoretically be possible, it would represent a fairly significant shift in the way Great Plains operates within a rapidly developing pricing environment and over a long holiday weekend. This is not a reasonable suggestion.

²⁹⁰ Ex. 300 at Attach. A (Jacobson Direct).

February Event, however, such adjustments had not been made and curtailments had never been used under these circumstances. Therefore, it was reasonable for Great Plains not to engage in curtailments and the Department's proposed disallowance on this issue should be denied.

C. Financial Hedging Strategies

184. The OAG asserts that there were "potential" hedges that the Gas Utilities "may have been able to pursue," either in the short-term (during February 2021) or longer-term (a year or more ahead of time), which could have offset some of the extraordinary gas costs incurred.²⁹¹ According to Mr. Lebens, the OAG's witness, the Gas Utilities could have pursued daily, weekly or short-term options²⁹² to mitigate exposure to extraordinary gas costs experienced during the February Event and "may have been able to pursue customizable over-the-counter (OTC) contracts that cap the maximum price that they would have paid."²⁹³

185. Specifically, the OAG contended that the utilities could have negotiated customized swing contracts with suppliers that included a "pre-negotiated . . . maximum, or ceiling, price above which [the utilities] would not have had to pay"²⁹⁴ Mr. Lebens noted: "In order to enter into such an agreement, a potential counter party may request things like (1) an up-front payment (a premium) in exchange for agreeing to a ceiling price or (2) the counter party may also ask the utility to agree to a floor price below which the gas would not be priced."²⁹⁵

186. Mr. Lebens reviewed monthly call options to illustrate the type of savings utilities could have achieved if they had negotiated hedges into some of their swing supply contracts,²⁹⁶ and asserted the utilities could have saved in the range of \$71 to \$92 million by engaging in hedging practices.²⁹⁷ The monthly call options that Mr. Lebens explored were illustrative, and were not intended to precisely mitigate a spike in the daily market.²⁹⁸ Mr. Lebens opined, however, that the performance of these options provided a proxy for how a relatively small number of hedged swing contracts would have performed had utilities put them in place prior to the spike.²⁹⁹ Mr. Lebens further opined that "given enough planning ahead of time [utilities] could have completely avoided [the Extraordinary Costs]."³⁰⁰

²⁹¹ Ex. 600 at 2 (Lebens Direct).

²⁹² "The calls and puts OAG discusses are the purchase and sale of options to trade gas futures contracts at a specified price on the Chicago Mercantile Exchange (CME) at Henry Hub (Henry) in Louisiana." Ex. 101 at 4-5 (Smead Rebuttal).

²⁹³ Ex. 600 at 6 (Lebens Direct).

²⁹⁴ *Id.* at 11.

²⁹⁵ *Id.*

²⁹⁶ *See id.* at 15-24.

²⁹⁷ *Id.* at 43.

²⁹⁸ *See id.* at 7 (stating that monthly call options "do not fully hedge against" "price spikes for short-term gas supply during the middle of the month").

²⁹⁹ Ex. 603 at 3, 13 (Lebens Surrebuttal).

³⁰⁰ *Id.* at 13.

187. Therefore, the OAG recommended that if the Commission found that the Gas Utilities should have both: (1) negotiated collars into their swing contracts; and (2) should not have been exposed to the risk of spot market prices, the Commission should disallow the full \$661,537,779 in extraordinary gas costs for all of the Gas Utilities.³⁰¹ Alternatively, he opined that a reasonable disallowance based on actual hedges would be in the range of approximately \$71 million to \$92 million, across all four entities.³⁰²

188. Great Plains contends that the OAG's position is unreasonable because it (1) relies on Henry Hub pricing, which is too remote from the Gas Utilities' markets to be a useful hedging tool; (2) relies on purely hypothetical hedging products that do not actually exist; (3) fails to recognize that a "costless" collar is not "costless" and would expose a utility to having to purchase excess gas at above market prices; and (4) employs hindsight by starting with known outcomes and working backwards to describe a "hedging" product that would have protected against that outcome.³⁰³

189. First, the OAG discussed hedging products related to trades at Henry in Erath, Louisiana – over 1,000 miles away from the Gas Utilities' market where the primary supply points or areas are Demarc, Ventura, and Emerson.³⁰⁴ During the evidentiary hearing Mr. Lebens conceded that he was not aware of the availability of futures contracts on the CME exchange that are priced at Demarc and Ventura.³⁰⁵ Great Plains also asserts that no market participant would willingly give up the "basis spread" between pricing at the different locations, relying on Mr. Smead's testimony that "[s]ellers who have produced or obtained their supply in Texas, Oklahoma, North Dakota, or Canada and then paid to have it transported to Demarc or Ventura would never price according to a completely unrelated point such as Henry. If they have committed to supply gas on call, as is the case in the swing contracts, they would never agree to forego the market value of that gas *at those points*."³⁰⁶

190. Related to the OAG's position that the utilities could have obtained options with "collars" capping the price for gas, Great Plains contends such products would not have offset the gas costs incurred during the February Event, because "such options can only be exercised to buy a futures contract *before the month to which the futures contract would apply*. They cannot be exercised in the middle of a month (e.g., February 8 for

³⁰¹ Ex. 600 at 43 (Lebens Direct).

³⁰² *Id.* at 44.

³⁰³ Ex. 101 at 4 (Smead Rebuttal).

³⁰⁴ *Id.* at 6. According to the Gas Utilities' witness Mr. Smead, "[a]ll of these points are extremely remote from Henry, not directly connected to Henry, and characterized by their own price dynamics independent of Henry. The spike in market gas costs experienced by the Joint Utilities was caused by market conditions that affected pricing at the supply hubs serving the Joint Utilities, not at Henry" *Id.* Mr. Smead further articulated that Henry's geographic and economic separateness is demonstrated by the stark difference in pricing during the February Event where the price of gas at Demarc and Ventura reached \$223.12/Dth and \$171.37/Dth higher than the price for gas at Henry, respectively. *Id.* at 7.

³⁰⁵ Evidentiary Hearing Tr. Vol. 3 at 18 (Lebens).

³⁰⁶ Ex. 101 at 7, 11 (Smead Rebuttal).

February supply) when an unanticipated spike in gas cost takes place after the start of the month.”³⁰⁷ Great Plains also contends that these options would expose the Gas Utilities to significant price risk because buyers can be forced to take excess gas that would need to be disposed of at lower prices.³⁰⁸ Further, such options would need to be negotiated in advance of the heating season, when the utility does not know how much gas its customers will consume because demand is tied to varying weather.³⁰⁹ In addition, “in order to achieve costless collars, the end result is frequently (and predominately) a level of puts that significantly exceeds the level of call options, in order to balance the market values of the two options and thus the willingness or unwillingness of counterparties to engage with them.”³¹⁰

191. Great Plains contends that the OAG’s suggested strategy would result in a utility being exposed to the risk that it could be forced to take larger volumes than necessary to meet demand during a warmer than normal winter at prices above daily market prices.³¹¹ Mr. Lebens acknowledged at the hearing, that the types of hedging instruments the OAG supports require a willing counterparty and that counterparty will have the same market and pricing (current and historical) information available to Great Plains.³¹² Great Plains provided testimony to the effect that buyers and sellers have the same information, and “any theory that some buyer or some seller could achieve a better price than the rest of the market is fundamentally flawed.”³¹³

192. Great Plains notes that speculative hedging may be appropriate for a pure play gas trader, but it does not comport with a utility’s principal obligation, which is to ensure safe and reliable gas service to its customers, not attempt to profit from gas trading.³¹⁴ “Great Plains does not participate in options trading because of the inherent financial risks associated with doing so . . . Great Plains does not feel options trading is in the best interest of its customers and such actions have not been authorized by the Commission.”³¹⁵

³⁰⁷ *Id.* at 13.

³⁰⁸ *Id.* Mr. Smead stated: “If engaging in such collars were business as usual, at a level to accommodate all of the utilities’ swing gas, these additional costs would happen frequently over many years, leading to very large cumulative ratepayer costs, and still not protect against a totally unprecedented event such as [the February Event].” *Id.*

³⁰⁹ *Id.* at 16.

³¹⁰ *Id.*

³¹¹ *Id.*

³¹² Evidentiary Hearing Tr. Vol. 3 at 28 (Leben) (“Q. And you would agree that natural gas suppliers also were aware of publicly available market information concerning the factors that led to the price spike that resulted during the February market event? A. Yes. Q. And you would agree that going back historically natural gas suppliers are also aware of the historical information of prior price spikes or prior activity -- prior incidents in the market that would inform pricing related to seasonal hedges? A. I was with you until you said seasonal hedges. But, yeah. Yes. Q. Okay. And you would agree that just because a utility might seek to execute a swing option or a swing contract does not mean that natural gas suppliers would be willing to engage in such transactions? A. Yes.”).

³¹³ Ex. 305 at 23 (Porter Direct).

³¹⁴ Great Plains Initial Br. at 34 (Mar. 15, 2022) (eDocket No. 20223-183828-01).

³¹⁵ Ex. 304 at 17 (Nieuwsma Rebuttal).

193. Great Plains also criticizes the OAG's position related to actual hedging results. It notes that the OAG's examples relate to Henry Hub pricing, though Henry does not provide physical supply to any of the Gas Utilities' delivery points, meaning "the trade would be purely financial and speculative, providing no supply at Demarc or Ventura."³¹⁶

194. Further, the illustrative examples used by the OAG related to options for March gas, not February, so the prices plotted could not possibly have impacted the price of February purchases. All of the options and futures relevant to February were traded before the beginning of the month.³¹⁷ Under these circumstances, Mr. Smead opined that "[f]or an investment in March options to be reasonable at that point, any investor would have needed two pieces of knowledge that *could not have been reasonably known or knowable at that time*: (1) a clear picture of what was about to happen in February (which no one in the industry had), and (2) an expectation that if February markets spiked to unprecedented levels for a few days, the option market for *March* gas would *also* go crazy for a short period, despite the virtual certainty that March markets would be unrelated to what was happening in February."³¹⁸ According to Great Plains, the hedging strategy (options trading) as described by Mr. Lebens are "highly speculative," and rely "on numerous assumptions and predictions and requires the participant to accurately time the market."³¹⁹

195. Finally, Great Plains references its small size relative to other utilities, and notes that Great Plains has not been granted authorization to engage in financial hedging strategies.³²⁰ Great Plains concluded it is not in the best interests of its customers to engage in speculative financial hedging strategies in light of Great Plains' limited size and scope.³²¹

196. The OAG disputes that the size of a utility is a relevant consideration. It notes that Greater Minnesota Gas, a company even smaller than Great Plains, incurred no extraordinary costs.³²² Mr. Lebens speculates that Greater Minnesota Gas avoided extraordinary costs, likely due to its use of hedging strategies, however, Mr. Lebens acknowledged that he does not know whether Greater Minnesota Gas engages in hedging.³²³

³¹⁶ Ex. 101 at 19-20 (Smead Rebuttal).

³¹⁷ *Id.* at 20. Mr. Smead stated: "Because it cannot be directly relevant to the [Gas] Utilities' February supply at Demarc and Ventura, the hypothetical trade is nothing but commodity financial *speculation* in March options, which would not be prudent for a utility to make in my experience." *Id.*

³¹⁸ *Id.* at 21.

³¹⁹ Ex. 304 at 16 (Nieuwsma Rebuttal).

³²⁰ Great Plains Initial Br. at 36-37 (Mar. 15, 2022) (eDocket No. 20223-183828-01); *see also* Ex. 506 at 30 (King Direct) ("[Great Plains] does not have a financial hedging plan that is approved by the Commission. As a result, [Great Plains'] target is not fully comparable to the other Gas Utilities for reasons further discussed below.").

³²¹ Ex. 304 at 17, 21-22 (Nieuwsma Rebuttal). Great Plains also contends that it does not trade in contracts at the size of those discussed in Mr. Lebens testimony. *See* Ex. 600 at 32 (Lebens Direct); *see also* Ex. 303 at 11 (Nieuwsma Direct); Ex. 304 at 21-22 (Nieuwsma Rebuttal).

³²² Ex. 603 at 15 (Lebens Surrebuttal).

³²³ Evidentiary Hearing Tr. Vol. 3 at 11, 37 (Lebens).

197. The record shows that the hedging strategies proposed by the OAG would have required Great Plains to change its practices to engage in hedging strategies well before the February Event took place, when Great Plains had no knowledge that the February Event would occur. The OAG's proposals rely on speculation as the products and pricing that would have been available during the February Event, and provide illustrations that are intended to mimic how such products would have been used, but that are too attenuated to be reliable as a basis for disallowance.

198. Prudence did not require Great Plains to engage in the hedging strategies proposed by the OAG. If the Commission wishes to explore whether the Gas Utilities should be required to engage in hedging, it may do so in the docket considering forward-looking strategies. As to the February Event, however, the disallowance proposed by the OAG is not supported by the record.

Based upon the foregoing Findings of Fact, the Administrative Law Judges make the following:

CONCLUSIONS OF LAW

1. The Commission and the Administrative Law Judges have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50, 216B.03 (2020).

2. The Commission has complied with all procedural requirements of law and rule, and the parties have had notice and an opportunity to fully participate in this proceeding. Therefore, this matter is properly before the Commission and the Administrative Law Judges.

3. Every rate made, demanded, or received by any public utility must be just and reasonable.³²⁴

4. The burden to prove that its actions were prudent and that recovery of extraordinary costs is reasonable rests on Great Plains.³²⁵

5. Utilities do not enjoy a presumption of prudence.³²⁶ Doubts as to reasonableness are resolved in favor of the consumer.³²⁷

6. Great Plains has established that its actions during the February Event were prudent and that recovery of its extraordinary costs is warranted.

³²⁴ Minn. Stat. § 216B.03.

³²⁵ See Minn. Stat. § 216B.16, subd. 4.

³²⁶ *In re a Comm'n Investigation into Xcel Energy's Monticello Life-Cycle Management/Extender Power Uprate Project*, MPUC Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes (May 8, 2015).

³²⁷ Minn. Stat. § 216B.03; see also Order for Hearing at 3 ("In incurring costs necessary to provide service, utilities are expected to act prudently to protect ratepayers from unreasonable risks.").

7. The record does not support disallowing extraordinary costs incurred by Great Plains in connection with the February Event.

Based upon the Findings of Fact and Conclusions of Law, the Administrative Law Judges make the following:

RECOMMENDATION

1. The extraordinary gas costs incurred by Great Plains to serve its customers during the February Event were prudently incurred.

2. No disallowance is warranted, and it is reasonable for Great Plains to recover the gas costs incurred during the February Event from its customers according to the recovery period established by the Commission.

3. Great Plains shall make further compliance filings as ordered by the Commission.

Dated: May 24, 2022



JESSICA A. PALMER-DENIG
Administrative Law Judge



BARBARA J. CASE
Administrative Law Judge

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.1275, .2700 (2021), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

May 24, 2022

See Attached Service List

Re: *In the Matter of the Petitions for Recovery of Certain Gas Costs*

***In the Matter of the Petition by Great Plains Natural Gas Co., a
Division of Montana-Dakota Utilities Co., for Approval of Rule
Variances to Recover High Natural Gas Costs from February 2021***

**OAH 71-2500-37763
MPUC G-004/M-21-235**

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** in the above-entitled matter.

If you have any questions, please contact me at (651) 361-7874, michelle.severson@state.mn.us, or via facsimile at (651) 539-0310.

Sincerely,



MICHELLE SEVERSON
Legal Assistant

Enclosure

cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

<p>In the Matter of the Petitions for Recovery of Certain Gas Costs</p> <p>In the Matter of the Petition by Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co., for Approval of Rule Variances to Recover High Natural Gas Costs from February 2021</p>	<p>OAH Docket No.: 71-2500-37763 MPUC G-004/M-21-235</p>
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Michelle Severson certifies that on May 24, 2022, she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy
James H.	Barkley	james.barkley@bakerbotts.com	Baker Botts
Brenda A.	Bjorklund	brenda.bjorklund@centerpointenergy.com	CenterPoint Energy
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP
Barbara	Case	barbara.case@state.mn.us	Office of Administrative Hearings
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY
Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP
Travis	Jacobson	travis.jacobson@mdu.com	Great Plains Natural Gas Company

Kyle R.	Kroll	kkroll@winthrop.com	Winthrop & Weinstine, P.A.
Erica	Larson	erica.larson@centerpointenergy.com	CenterPoint Energy
Amber	Lee	Amber.Lee@centerpointenergy.com	CenterPoint Energy
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP
Jessica	Palmer Denig	jessica.palmer-Denig@state.mn.us	Office of Administrative Hearings
Lisa	Peterson	lisa.r.peterson@xcelenergy.com	Xcel Energy
Catherine	Phillips	Catherine.Phillips@wecenergygroup.com	Minnesota Energy Resources
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates
Peggy	Sorum	peggy.sorum@centerpointenergy.com	CenterPoint Energy
Richard	Stasik	richard.stasik@wecenergygroup.com	Minnesota Energy Resources Corporation (HOLDING)
Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine
Michael A.	Yuffee	michael.yuffee@bakerbotts.com	Baker Botts