BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

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	ISSUE DATE: October 19, 2022 DOCKET NO. G-004/M-21-235
In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers	DOCKET NO. G-999/CI-21-135 ORDER DISALLOWING RECOVERY OF CERTAIN NATURAL GAS COSTS AND REQUIRING FURTHER ACTION

PROCEDURAL HISTORY

I. Introduction

In February 2021, cold weather across much of the United States led to increased demand for natural gas and, in some areas, supply disruptions. An extreme rise in natural gas prices ensued. Minnesota's regulated gas utilities maintained continuous service to customers throughout this period, but some incurred unprecedented costs purchasing gas on the spot market. Under Commission rules, such costs ordinarily are billed to ratepayers through an automatic purchased-gas adjustment to customer rates over the next 12-month period beginning on September 1 each year. However, the extreme circumstances in this case prompted the Commission to initiate an investigation.

On March 2, 2021, the Commission opened an investigation into the impacts of the event and directed the affected gas utilities subject to its ratemaking authority[1] to file information about the reasons for and details of the price spike, their responses to the spike, and customer impacts, as

[1] The affected natural gas utilities are CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas (CenterPoint); Northern States Power Company d/b/a Xcel Energy (Xcel); Minnesota Energy Resources Corporation (MERC); Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co. (Great Plains or the Company).

well as the utilities' gas supply planning and purchasing strategies and how utilities could or should alter those strategies in anticipation of increasingly frequent extreme weather events.[2]

II. Purchased-Gas Adjustment

Total annual gas costs are reviewed when utilities file their annual automatic adjustment (AAA) reports by September 1 each year. These reports include detailed information about all automatic adjustment charges made in the 12-month period from July 1 of the previous year to June 30 of the reporting year.[3] The reports show, by customer class, the difference between gas costs actually incurred and those collected from ratepayers, and include a proposed plan to reconcile (true-up) this difference by increasing or refunding rates over the next 12-month billing cycle.[4]

Given the magnitude of costs reportedly incurred during February 13–17, 2021 (the February Event), the likelihood of rate shock, and the need to mitigate customer impacts, the affected utilities proposed variances to the Commission's automatic-adjustment rules to authorize them to separately track their extraordinary costs related to the February Event and recover those costs over an extended period using a surcharge separate from the AAA true-up mechanism.

III. Variance Requests and August 30, 2021 Order

On March 30, 2021, Great Plains filed its petition requesting rule variances to modify recovery of $11 million in February 2021 gas costs over an extended period using a surcharge separate from the AAA true-up mechanism.[5]

On August 30, 2021, the Commission issued an order granting Great Plains' request for a rule variance and approved a special surcharge that distributes extraordinary gas costs over an extended period using a seasonally adjusted schedule.[6] This action also applied to CenterPoint, Xcel, and MERC, and it was designed to mitigate ratepayer impacts by reducing the size of each monthly surcharge and by reducing the surcharge rate in the winter, when many customers incur higher gas bills.

For purposes of the variance and the special recovery mechanism, the Commission defined "extraordinary gas costs" or "extraordinary costs" as the margin between $20.00 per Dekatherm (Dth) and the actual average price paid by the utilities during the February Event.[7]

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[2] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers*, Docket No. G-999/CI-21-135, Order Opening Investigation (March 2, 2021).

[3] Minn. R. 7825.2810; Minn. R. 7825.2910, subp. 4.

[4] Minn. R. 7825.2700, subp. 7; Minn. R. 7825.2810; Minn. R. 7825.2910, subp. 4.

[5] The other three affected natural gas utilities (CenterPoint, Xcel, and MERC) also requested similar variances and extended recovery periods.

[6] Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing, at 20–21, Ordering Paras. 6–11 (August 30, 2021).

[7] *Id.* at 20, Ordering Para. 3. The total claimed extraordinary gas costs are: $408,755,953 for CenterPoint; $178,978,695 for Xcel; $64,975,882 for MERC; and $8,827,249 for Great Plains. *Id.*, Ordering Para. 4.

Applying the Commission's definitions, Great Plains requested to recover a total of $8,827,249 in extraordinary gas costs through the February-Event surcharge.

The Commission's August 2021 decision precluded the utilities from charging ratepayers interest or financing costs related to the extraordinary gas costs,[8] and it exempted certain low-income customers from the surcharge.[9] With these limitations, the Commission authorized utilities to begin recovering extraordinary costs from customers through the approved surcharge mechanism pending a review of whether the costs were incurred prudently. The order emphasized that each utility bears the burden to prove the prudence and reasonableness of its costs, and any costs not proven to be prudent and reasonable would be disallowed or refunded to customers.

IV. Proceedings Before the Administrative Law Judges

As part of its decision granting the rule variances described above, the Commission also referred the matters to the Office of Administrative Hearings for contested-case proceedings to develop the record on whether each utility acted prudently in relation to the February Event and whether it is just and reasonable for each utility to recover all extraordinary costs from ratepayers.[10] The investigations proceeded jointly in four utility-specific Commission dockets: G-008/M-21-138 (CenterPoint), G-004/M-21-235 (Great Plains), G-002/CI-21-610 (Xcel), and G-011/CI-21-611 (MERC).[11]

The Office of Administrative Hearings assigned Administrative Law Judges Jessica A. Palmer-Denig and Barbara J. Case to hear these matters.

From October 2021 through February 2022, the following parties filed written direct, rebuttal, and surrebuttal testimony:

- The affected gas utilities, jointly and individually;
- The Citizens Utility Board of Minnesota (CUB);[12]
- The Department of Commerce, Division of Energy Resources (the Department); and
- The Office of the Attorney General—Residential Utilities Division (the OAG).

On February 17–18 and 22, 2022, the Administrative Law Judges (ALJs) held evidentiary hearings.

[8] *Id.* at 21, Ordering Para. 16.

[9] *Id.* Ordering Para. 12.

[10] *Id.* at 22, Ordering Paras. 21 & 23.

[11] The Commission will address the results of each investigation in a separate, utility-specific order in each utility's respective docket.

[12] Due to resource constraints, CUB did not closely review Great Plains' actions at issue in this docket and made no disallowance recommendations. CUB noted that its lack of recommendations should not be interpreted to mean that CUB found any of Great Plains' extraordinary costs to be prudently incurred.

A public comment period was open from February 7 through March 4, 2022, and remote-access public hearings were held on March 3. After the comment period closed, members of the public continued to submit written comments into August.

On March 15, 2022, CenterPoint, Great Plains, Xcel, MERC, CUB, the Department, and the OAG filed initial post-hearing briefs and proposed findings of fact.

On March 25, 2022, Xcel, CenterPoint, Great Plains, MERC, CUB, the Department, and the OAG filed reply briefs.

V. Proceedings Before the Commission

On May 24, 2022, the ALJs issued four sets of Findings of Fact, Conclusions of Law, and Recommendations (ALJ Reports), each specific to one utility. The ALJ Reports concluded that each of the affected utilities acted prudently and should fully recover its extraordinary costs.

On June 3, 2022, the Department, the OAG, CUB, and the City of Minneapolis filed exceptions disagreeing with the ALJ Reports. CenterPoint; Great Plains; Xcel; MERC; and the Laborers' International Union of North America, Minnesota and North Dakota filed letters recommending that the Commission adopt the ALJs' findings, conclusions, and recommendations.

On August 4 and 11, 2022, the Commission heard oral argument from and asked questions of the parties. On August 11, the record closed under Minn. Stat. § 14.61, subd. 2.

FINDINGS AND CONCLUSIONS

I. Introduction

A. Legal Standard

Under Minn. Stat. § 216B.03,

> Every rate made, demanded, or received by any public utility . . . shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers . . . . Any doubt as to reasonableness should be resolved in favor of the consumer.

When a utility proposes annual purchased-gas-cost adjustments to recover or refund amounts for gas purchases made in the 12-month period between July 1 and June 30 of the preceding year, the proposal is governed by the Commission's rules set forth in chapter 7825 of the Minnesota Rules. Minn. R. 7825.2390 explains the purpose of the relevant rule parts:

> The purpose of parts 7825.2390 to 7825.2920 is to enable regulated gas and electric utilities to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized by the commission in the utility's most recent general

> rate case. Energy costs included in rate schedules are subject to evidentiary hearings in general rate cases filed by the utility. Proposed energy cost adjustments must be submitted to the Department of Commerce. Annual evaluations of energy cost adjustments are made by the Department of Commerce and others as provided for in parts 7825.2390 to 7825.2920.
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> When a utility proposes new or revised electric energy or purchased gas adjustment provisions, the proposal is considered a change in rates and must be reviewed according to commission rules and practices relating to utility rate changes.[13]

B. Burden of Proof

The burden is on the utility to prove its costs were incurred prudently and will result in just and reasonable rates.[14] Any doubt as to reasonableness is to be resolved in favor of the consumer.[15] There is no burden on agencies or other intervenors to precisely identify which imprudent actions caused which costs in order to justify a disallowance.[16] Merely showing that the utility incurred expenses does not meet the utility's burden of demonstrating that it is just and reasonable for ratepayers to bear those expenses.[17]

C. Prudence Standard

When evaluating whether costs are just and reasonable, the Commission determines whether a utility acted prudently in incurring the costs. In this proceeding, the prudence standard is not in dispute among the parties.

Generally, prudence is reasonable action taken in good faith based on knowledge available at the time of the action or decision. Actions taken in good faith are those taken without malicious intent, exercising the care that a reasonable person would exercise under the same circumstances at the time the decision was made. It is not evaluated using the benefit of hindsight.

Under this standard, gas utilities' actions and decisions are evaluated based on 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.

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[13] Minn. R. 7825.2390.

[14] Minn. Stat. § 216B.16, subd. 4.

[15] Minn. Stat. § 216B.03.

[16] *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes, at 13 (May 8, 2015).

[17] *In re N. States Power Co.*, 416 N.W.2d 719, 723 (Minn. 1987).

II. The Administrative Law Judges' Report

The ALJs presided over three days of evidentiary hearings and two public hearings. They reviewed the testimony of expert witnesses and examined exhibits. In the ALJ Report on Great Plains' February Event costs, the ALJs made more than 200 findings of fact, conclusions, and recommendations on the stipulated and contested issues.

Having itself examined the record and having considered the ALJ Report, the Commission concurs in many of the ALJs' findings and conclusions. However, the Commission reaches different conclusions on some issues—including questions of whether certain extraordinary costs were incurred prudently—as set forth below. On all other issues, the Commission accepts, adopts, and incorporates their findings, conclusions, and recommendations.

III. Public Comments

Many members of the public submitted comments throughout these proceedings. Virtually all of these commenters supported disallowing recovery of some or all of the extraordinary gas costs incurred by one or more of the impacted gas utilities during the February Event.

Generally, these commenters contended that the utilities did not act prudently to protect customers from extraordinary gas costs and that it would be unjust and unreasonable to pass these costs on to customers, who were in no position to avoid or mitigate the costs. Many commenters expressed that it would be difficult or impossible for them to pay these additional costs and that the utilities were in a better position to absorb the financial impact. Some commentors also criticized the gas utilities' failure to communicate with customers before or during the February Event to encourage conservation measures that could have mitigated costs by reducing the total load the utilities needed to serve during the high-price period and relieved some of the demand-related pressure on market prices.

IV. The Department of Commerce

The Department plays a pivotal role in the evaluation of utilities' AAA reports by receiving and closely evaluating the filings and making recommendations to the Commission.[18] The Department's application of its expertise in analyzing the filings facilitates a careful, comprehensive, and thorough examination that informs the Commission's weighing of evidence, as well as the balancing of the interests of the utility and its customers. The Commission appreciates the extensive analysis undertaken by the Department to fulfill its role in developing the record in this case.

V. Factual Background

A. Introduction

In February 2021, a winter-weather event brought extremely cold weather to parts of the United States, including Minnesota and the natural-gas-producing regions of Texas and Oklahoma. These cold temperatures caused significant disruption in the production and distribution of natural gas.

[18] Minn. R. 7829.2390.

The price of wholesale natural gas is not regulated and it is set dynamically through interactions between buyers and sellers based on factors impacting supply and demand. During the February Event, natural gas prices reached unprecedented highs due to system-wide decreases in supply and increases in demand—both caused by unexpectedly cold weather. Additionally, prices began to increase on a Friday going into a holiday weekend, which forced purchasers of natural gas to enter into agreements with uncertain pricing to secure deliveries of natural gas for a four-day period until regular trading resumed the following Tuesday.

B. U.S. Natural Gas Markets

The natural gas commodity market is comprised of: (1) producers that drill wells and bring raw natural gas to the surface; (2) midstream gathering and processing entities that carry the raw gas to treatment and processing facilities; (3) operators of transmission pipelines that move dry (processed) gas and gas from storage to distant consuming markets; (4) storage providers that offer underground natural gas storage for future consumption, which can include system balancing; and (5) local gas utilities like Great Plains that supply and deliver natural gas to customers.

Natural gas is not produced within Minnesota, so interstate pipelines must be used to transport the gas that will ultimately be used by consumers. Throughout the pipeline network exist various market hubs, which are often located at the intersections of pipelines or include key supporting facilities such as storage. Demarc (Kansas), Ventura (Iowa), and Emerson (Manitoba) are three market hubs directly relevant to the Great Plains' distribution system.[19]

1. Transactions

Gas utilities must contract with two different types of entities to serve their customers. First, the gas utility contracts with transportation pipelines serving its location to purchase pipeline capacity sufficient to ensure that the appropriate amount of natural gas can be transported when needed by the gas utility. These types of agreements are entered into pursuant to tariffs regulated by the Federal Energy Regulatory Commission. Second, the gas utility must contract with suppliers to secure the natural gas commodity that will travel through the transportation pipelines.

The natural gas market is subject to extensive reporting, observation, and analysis, but the wholesale trading of natural gas as a commodity is not regulated and prices are determined in a competitive market. Many factors can influence the price of natural gas, including weather forecasts, storage levels and activity, current and projected production levels, demand for liquefied natural gas exports, pipeline constraints, pipeline tariff provisions and operational actions, and uncertainty of supply reliability.

Purchase and sale of natural gas occurs through both bilateral negotiations between counterparties and open and transparent trading on organized and regulated commodity exchanges such as the Chicago Mercantile Exchange and the Intercontinental Exchange. These fixed-price trades are based on an agreed-to dollar-amount per unit.

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[19] In addition to these market hubs, Great Plains has primary receipt capacity at Carlton, Marshall, Ogden, and Chisago.

Rather than relying on a fixed-price structure, most transactions for physical natural gas are priced according to a published index designed to be representative of the average market rate for the day at specific market hub locations. Price-reporting agencies calculate prices based on weighted averages derived from the reported fixed-price transactions and publish them on an index such as S&P Global Platts Gas Daily (Gas Daily).

Fixed-price transactions allow buyers or sellers to potentially beat the index, but they also can create more risk because it is uncertain at the time of the contract whether the agreed-to fixed price will end up above or below where published index prices settle. Gas utilities are not generally expected to beat the index, and because index pricing distributes price-fluctuation risk equally between buyer and seller, the vast majority of transactions set prices based on an index.[20] During periods of high actual or expected volatility, index deals may become more attractive and may be the only available pricing option. Parties to an index-price transaction will not know the final price when they enter the agreement, but they can be confident that it will reflect an average price of actual transactions and generally be consistent with the market rate.[21]

Once physical natural gas is purchased, it needs to be scheduled (or nominated) to flow on transportation pipelines. The Federal Energy Regulatory Commission requires transportation pipelines to incorporate nomination standards developed by the North American Energy Standards Board into their tariffs. These standards set five different cycles upon which natural gas can be nominated—two during the day prior to when the gas will flow, and three opportunities on the day gas will flow. This pipeline nomination structure creates limited ability to respond to changes during the day by buying and selling flowing gas supply.

When a transportation pipeline experiences certain strained operating conditions, it may declare "critical day," "system underrun limitation," or "system overrun limitation." Once these conditions are declared, gas utilities can be exposed to significant penalties under the terms of applicable tariffs for taking excess gas. These penalties can be up to two to three times the settled daily index price per unit. Because the penalty is a multiple of the prevailing market price, during times of high prices, pipeline users have a strong economic incentive to purchase enough scheduled, flowing supply to not exceed the scheduled quantity.

2. Natural Gas Supply Options

Gas utilities acquire natural gas supply through baseload purchase, storage assets, swing supply, and daily spot purchases.

Baseload or base supply purchases refer to fixed volumes of gas that flow every day for the term of the contract, which are monthly or longer-term contracts. Great Plains enters base supply agreements with pricing pursuant to first-of-the-month index or a fixed price. Utilizing base supply typically provides price stability because first-of-the-month indexes have lower volatility

[20] In 2020, about 84% of the physical daily and monthly agreements were based on index price.

[21] While the specific final index dollar amount is unknown at the time of the contract, market participants are able to estimate where the price might settle based on observations of current and historical market trends.

than daily price indexes. Great Plains may accept fixed-price offers for base supply when it determines they are competitive with or better than first-of-the-month index offers.

Great Plains is unable to rely on base supply to meet all of its demand needs because demand, which is largely inversely correlated to temperature, fluctuates daily throughout a contract's term. Purchasing more gas than needed can subject the purchaser to penalties under pipeline tariffs when it is unable to receive the gas from the pipeline.

Storage supplies are filled during the summer season when demand is low and typically deployed during the higher demand winter season. Contracts governing pipeline and virtual marketer storage dictate terms of how these assets can be deployed, including for example, maximum daily withdrawal limits.

Swing supply is a secured commitment from a supplier to deliver an agreed-upon volume of supply at the option or request of the buyer. Swing supply provides assurance that a quantity of physical gas will be available, but the price is often based on the daily index.

Daily spot purchases refer to gas purchased on the spot market for delivery the next day (or next several days if intervening weekend/holiday). Daily spot purchases can exist with fixed prices or index pricing, but because these contracts are created in the day or days before the gas is needed, their availability fluctuates and depends on seller supply and willingness to transact, so daily spot gas may not always be available to purchase.

Swing supply and daily spot purchases serve similar functions in the market by satisfying short-term demand one to several days in advance of the anticipated need. If spot purchases are priced based on the same index as comparable swing supply, the key determinant is the adder (premium or discount) to the relevant settled index price. Prior to calling on its reserved swing purchases, Great Plains will search for comparable daily spot offers and enter into those agreements if they are cheaper.

C. Natural Gas Supply Planning

Great Plains provides retail natural gas service to approximately 22,500 customers in 18 communities in western Minnesota. Each year, Great Plains analyzes the natural gas supply needs of its customers and contracts for pipeline capacity from Viking Gas Transmission Company (VGT) and Northern Natural Gas Co. (NNG). Great Plains contracts for pipeline capacity sufficient to satisfy demand on a design cold weather day to ensure that it will be able to deliver reliable service to its customers throughout the year.[22]

Gas planning decisions are informed by resource optimization software, which utilizes data on gas supply options, contract terms, normalized weather, contracted pipeline capacity quantities and costs, storage capabilities and costs, and forecasted gas pricing to develop a least-cost operating plan and mix of gas supply options for the year. The software is a key resource for gas

[22] "Design day" is a concept used in capacity planning to represent a 24-hour-day period of the greatest possible gas requirement to meet firm customers' needs. Minn. R. 7825.2400, subp. 13d. Design-day conditions occur infrequently and did not occur during the February Event.

supply managers because it allows them to test and verify weather, price, and resource combinations when planning for and throughout the winter heating season.

Prior to each winter heating season, Great Plains enters into agreements with natural gas suppliers to secure adequate base and swing supply for the upcoming colder months. Great Plains attempts to build its gas supply portfolio with a geographically diverse mix of supply that is provided by suppliers with demonstrated reliable performance. Great Plains plans to meet 75% of normal demand through a combination of base supply and storage.

During this planning period, Great Plains issues requests for proposals soliciting offers from natural gas suppliers. Great Plains evaluates the supplier offers it receives based on pricing, term, quantity, supply source diversity, and supplier diversity to determine the most reliable and cost-effective supply portfolio.

Great Plains does not always receive offers for specific types of supply solicited in its requests for proposals. For example, it received no offers for guaranteed swing supply from Emerson for the 2020–2021 heating season. Because Emerson has less liquidity[23] than Ventura or Demarc, Great Plains elected to utilize its available capacity from Emerson to receive base supply.

D. Gas Purchasing During the February Event

The extraordinary costs at issue before the Commission arose from gas purchases Great Plains made on the daily spot market to serve Minnesota customers during the February Event.

The natural gas daily spot market typically operates in a day-ahead fashion, meaning trades occur on the business day before delivery. The market does not formally operate on weekends or holidays, so trades preceding weekends or holidays usually cover the period through the next business day. Purchases covering weekends and holidays also must be "ratable," which means the buyer must purchase the same volume of gas for each day of that period.

The extraordinary gas costs at issue in this order came from transactions made on two occasions.

First, on the morning of Friday, February 12, 2021, Great Plains made daily spot gas purchases for the four-day period of February 13–16. This four-day period included a weekend, the Presidents' Day holiday on Monday, and the next business day, which was Tuesday. Great Plains was required to purchase the same volume of gas for each of these four days. Accordingly, Great Plains determined the volume of spot gas to purchase for the February 13–16 period based on its projected needs to serve the coldest forecasted day of that period, February 14.

Second, on the morning of Tuesday, February 16, Great Plains made spot gas purchases for February 17 only. These transactions covered only one day and were not required to match the volumes purchased for any other day.

[23] In this context, liquidity is based on the volume of throughput and number of counterparties willing and able to transact, so a purchaser may be unable to find desired spot gas purchases for a market hub with less liquidity.

Great Plains must finalize its gas purchasing decisions before 1:00 p.m. on the day of purchase to meet the deadline to make the necessary transportation pipeline nominations for the purchased gas. If it intends to use its swing supply, the contract requires that Great Plains make that decision by 7:45 a.m.

On the morning of February 12, Great Plains had determined that it needed approximately 33,000 Dth/day of total supply to meet its maximum expected customer demand over the four-day weekend from February 13–16. After relying on base supply and maximizing daily storage withdrawals, Great Plains called on its swing supply for the remaining daily supply requirement of 13,800 Dth because the offers it received for day gas were all index-based with a higher adder than its swing supply contract. Prior to the deadline to call on its swing supply, there were no posted fixed-price trades on the Intercontinental Exchange or fixed-price offers available from Great Plains' counterparties. Due to forecasted demand exceeding supply and Great Plains anticipating pipeline constraints, the Company purchased an additional 500 Dth/day for the four-day weekend.

Gas Daily settlement prices at Demarc and Ventura closed above $15/Dth for gas flowing on February 12.[24] In the afternoon on February 12, after Great Plains committed to its gas purchases for the four-day weekend, Gas Daily index prices for Demarc and Ventura settled at $231.67/Dth and $154.905/Dth, respectively.

On Tuesday, February 16, Great Plains finalized its gas planning and purchasing decisions for February 17. It utilized its available base supply but reduced its daily storage withdrawal to approximately half the daily maximum and purchased daily spot gas for its remaining projected needs. Index prices for these spot purchases from Demarc and Ventura settled at a weighted average of approximately $172/Dth.

The Department recommended disallowances related to the purchasing decisions Great Plains made on February 16 because of the Company's failure to maximize available storage withdrawals and curtail a portion of its interruptible customers on February 17. The OAG recommended disallowances related to all February Event extraordinary costs because Great Plains did not implement financial hedging strategies.

VI. Storage Utilization

A. Introduction

Storage assets provide gas utilities with a flexible resource that can be used for system balancing. Storage utilization can also mitigate costs because storage assets are filled in the summer when gas is cheaper, and the direct cost of using storage can be less than purchasing market-price gas during the heating season.

[24] Since 2016, Gas Daily Demarc had only settled above $8 on four days with a maximum daily index price of $8.475/Dth in March of 2019, and Gas Daily Ventura had only settled above $8 on seven days over the same period; Ventura's previous record high was $67.455 in December of 2017, which occurred over a holiday weekend.

Great Plains' storage inventory was 107,015 Dth at the beginning of February 2021. Its targeted end-of-month storage balance was 46,140 Dth. It remained on schedule for this target by withdrawing 2,174 Dth/day for the first ten days of February. On February 11, due to decreasing temperatures, the Company planned to increase its storage withdrawals.

On February 14, Great Plains fully utilized its available storage and reached its daily maximum withdrawal limit of 3,944 Dth. On February 16, the Company decided to revert back to its planned daily storage withdrawal level of 2,174 Dth for February 17.[25]

B. Positions of the Parties

1. The Department

The Department contended that Great Plains acted unreasonably on February 16 by failing to maximize its available storage withdrawals on February 17. It reasoned that Great Plains made unnecessary purchases of expensive spot gas rather than relying on its cheaper storage reserves.

The Department explained that Great Plains made unfounded decisions based on assumptions that gas prices on February 17 would return to pre-February Event levels. Email discussions between Great Plains' staff recognized the existence of an ongoing "risky price environment," but Great Plains' decision to reduce its storage withdrawals disregards the significant risk of continued high spot gas prices. By February 16, a reasonable utility would have understood that the then-ongoing February Event differed in scope and degree from previous price spikes such as the one that occurred over New Year's weekend in 2017–2018, so even if temperatures did increase (reducing demand), there was significant risk that the spiking gas prices would persist.

Contrary to Great Plains' assertion that it needed to reduce storage utilization on February 17 to preserve its storage capacity for the duration of the heating season, the Department noted that storage levels on February 16 were only slightly below the planned monthly target. Great Plains should have decreased storage utilization only once it was confident gas prices had stabilized, and it was unreasonable to revert back to its standard practices in the midst of an ongoing price crisis without any consideration of cost impacts to its customers.

The Department contended that Great Plains unreasonably relied on potential supply failures to justify underutilizing its storage capacity. The Department noted that Great Plains failed to quantify any of the supply failures that it stated occurred during the holiday weekend. Additionally, the Department stated that Great Plains failed to demonstrate why it would be unable to address the potential of any similar supply imbalances on February 17 through

[25] After maximizing storage withdrawals on February 14 and 15, Great Plains reduced its storage withdrawals on February 16 because temperatures were increasing and customer demand was decreasing. However, because it had already purchased swing gas for the entire four-day weekend (which included Tuesday, February 16) on a ratable basis at a volume tailored to meet its expected demand on the coldest day, the decreased withdrawal amount on February 16 occurred for system balancing and did not necessitate any additional purchases of spot gas.

curtailment, noting that Great Plains had the ability to curtail its interruptible customers if demand increased or supply cuts occurred.[26]

The Department's expert witness, Matthew J. King, testified that it was not unreasonable for gas utilities to operate with a supply reserve margin, which means planning for daily supply slightly in excess of forecasted daily load, but he asserted that the 13% supply reserve margin Great Plains used on February 17 was excessive, unexplained, and unreasonable.

The Department recommended using a 2% reserve margin because Minnesota gas utilities had planned for supply approximately 2% in excess of their forecasted load over the four-day weekend. The Department noted that Great Plains procured supply 1.8% in excess of its forecasted load on February 14. Additionally, King testified that a reasonable reserve margin level should be deliberately determined and explainable, and Great Plains failed to explain how it determined 13% was appropriate on February 17 when temperatures were moderating and demand was decreasing. Furthermore, the Department emphasized the cost risk posed to customers when a gas utility arbitrarily selects an excessive reserve margin as such practices could lead to imprudently incurred spending on expensive, unnecessary gas, the costs of which are typically passed on to customers.

Because Great Plains purchased expensive spot gas rather than utilizing its available storage on February 17, the Department recommended disallowing $439,450 for excess gas costs unnecessarily incurred due to Great Plains' failure to maximize storage withdrawals and by running a reserve margin of 13%, rather than 2%.

The OAG supported the Department's analysis and recommendations.

2. Great Plains

Great Plains described the Department's position as post-hoc rationalization and contended that the Company's decision makers believed that reduction in storage withdrawals on February 17 was reasonable.

First, Great Plains explained that its gas managers reasonably expected that prices would be returning to pre-spike levels. Forecasts predicted warmer temperatures, which should decrease gas demand and moderate price.[27] Additionally, prices had quickly returned to more normal levels during a previous holiday weekend price spike that occurred over the 2017–2018 New Year's weekend.

Second, Great Plains focused on the essential operational flexibility provided by storage assets both in the short and long term. Great Plains had exceeded its planned storage withdrawals for February, and gas managers wanted to rely less on storage so that its storage supply would remain closer to planned levels for the duration of the winter heating season. Maximizing daily

[26] Great Plains had 5,859 Dth of interruptible load. If the Company curtailed half of this load for economic benefit, approximately 2,930 Dth would have remained to address operational issues.

[27] Forecasts predicted February 17 temperatures to be 16–20 degrees warmer than temperatures on the coldest day of the previous four-day weekend.

storage withdrawals also generated short-term concerns about Great Plains' ability to address potential supply disruptions on February 17. Great Plains referenced the limited mitigation options it had available during the four-day weekend when it had maximized its daily storage withdrawals. Specifically, it stated that supply disruptions occurred from February 13–16, and because it had no storage available those days, its only alternative supply options were on the intra-day market or through load shedding.[28]

Great Plains also emphasized that the primary purpose of its gas storage reserves is to maintain reliability throughout the entire winter season. The Company stated that it would not typically withdraw stored gas for the purpose of moderating the economic impacts of price spikes. While it had maximized storage withdrawals during the four-day weekend, Great Plains noted that decision was then justified because customer demand approached peak levels.

Great Plains opposed the 2% reserve margin proposed by the Department because a 2% reserve would not allow the Company to adequately address potential supply disruptions or inaccuracies in weather forecasts. Additionally, Great Plains faulted the recommended reserve margin for failing to account for fuel-in-kind deductions imposed by pipeline tariffs.[29]

While Great Plains acknowledged that its reserve margin of 13% on February 17 may have been overly conservative in hindsight. But the Company argued that it was justified because this margin was deliberately selected based on actual demand consistently exceeding projected demand during the previous four-day weekend. Great Plains noted that realized temperatures on February 13–16 were 1–7 degrees colder than predicted at the time the Company made its purchasing decisions on February 12, and over the holiday weekend, actual load exceeded forecasted load by a daily range of 2,824 Dth to 5,226 Dth (9.6% to 16.6%).

3. The Department's Reply

The Department noted that Great Plains' emphasis on the inherent value of returning to its planned storage operations was not reasonable amidst ongoing, record-setting price spikes in the natural gas market.

Even if the rationale for Great Plains' 13% reserve margin is based on its experience during the previous four-day weekend, the Department contended that this still does not demonstrate how the figure is actually reasonable or justified. Great Plains had to make purchasing and gas planning decisions for each day of the four-day weekend on the morning of Friday, February 12, so it needed to rely on longer-term weather forecasts with a higher probability of being inaccurate compared to its decisions for February 17, which would have relied on forecasts generated only one day prior. Additionally, going into the weekend, temperatures were expected to decrease, whereas temperatures had begun to moderate by February 16, and forecasts indicated temperatures would continue to increase on February 17. The Department asserted that

[28] Great Plains noted that the scheduling imbalances that occurred over that weekend were ultimately within pipeline tolerances, so it faced no punitive damages.

[29] Tariffs permit interstate pipelines to impose "fuel-in-kind deductions" that reduce gas delivered to purchasers from the quantity purchased by a fixed percentage (ranging from near zero to 2%). Great Plains indicated that during the February Event, NNG's and VGT's fuel-in-kind deductions were 1.19% and 0.1%, respectively.

Great Plains' determination of a next-day reserve margin based on the outcomes of a four-day period with more uncertainty and different weather conditions was not reasonable.

The Department contended that its recommended 2% supply reserve margin is consistent with the industry practice and the concept of "being slightly long," while Great Plains' 13% excess was consistent with neither. The Department explained the importance of having supply reserve margins that are deliberately selected and explainable, noting that if the Commission allowed utilities to justify any excess purchase as a supply reserve margin after the fact, utilities would have unlimited discretion in load forecasting.[30] This would give utilities little incentive to accurately forecast, as opposed to over-forecast, load because they would always be able to pass on the gas expense to ratepayers, no matter how expensive or unnecessary the excess.

4. Great Plains' Reply

While the Department focused its argument on explaining why prioritizing the long-term availability of storage was unnecessary on February 17, Great Plains emphasized the short-term value of reserving some of its storage for February 17. Given that supply disruptions occurred over the holiday weekend, a force majeure had been in effect for NNG, and Great Plains' gas planners anticipated potential supply cuts, Great Plains argued that it was necessary and reasonable to reserve some storage capacity to address potential operational issues should they arise on February 17.

C. Recommendations of the Administrative Law Judges

The ALJs determined that it was unreasonable for Great Plains to expect prices on February 17 to return to normal levels but ultimately found that the record established that Great Plains' decision to revert to its storage plan for February 17 was reasonable and recommended no disallowances. The ALJs determined that the Department's argument inappropriately relies on elevating the consideration of the extreme price of gas over all other considerations. Noting that Great Plains and the other gas utilities were required to make decisions based on rapidly developing information in an unprecedented and complex gas-purchasing environment, the ALJs determined that Great Plains established that it considered a variety of factors and made a reasonable decision among a range of potentially reasonable options.

Similarly, the ALJs determined that Great Plains' 13% reserve margin was reasonable. The ALJs noted that the Department's proposed 2% reserve margin was not a recognized standard within the natural gas industry, and that the Department's position would essentially require the Commission to accept the 2% margin, notwithstanding all of the relevant circumstances, and then require Great Plains to disprove that figure, which the ALJs stated is inconsistent with the framework for evaluating prudence.

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[30] The Department elaborated that if the Commission determines a utility's action was not prudent, a disallowance should be calculated. Because the Department agreed that purchasing gas slightly in excess of forecasted load was prudent, it needed to apply a reasonable supply reserve margin to its calculations. By selecting the slightly long 2% supply reserve margin, the Department emphasized that it was ensuring the disallowances it recommended were remedial rather than punitive or arbitrary.

D. Commission Action

The Commission agrees with the ALJs that at the time Great Plains made purchasing decisions on February 16, it was unreasonable to expect gas prices to return to normal on February 17. The Company's position that prices would return to more normal levels on February 17 is inconsistent with contemporaneous concerns about needing to reserve storage capacity to protect against potential supply disruptions that day. Gas prices were so high over the holiday weekend that costs incurred for those four days were commensurate with typical costs for an entire winter heating season. Given that knowledge as of the morning of February 16, there was no reasonable basis to assume that prices would significantly moderate for gas purchased for February 17.

The Commission respectfully disagrees with the ALJs' determination that Great Plains proved its actions regarding storage utilization were prudent. The known and ongoing risk that gas prices would remain at or near historic highs obligated Great Plains to take reasonable steps to protect customers from any unnecessary purchases of spot gas to maintain rates that are just and reasonable. Great Plains' decisions for February 17 to reduce storage withdrawals and run an excessive 13% supply reserve margin were not prudent.

Contrary to the ALJs' assertion that a finding of imprudence would require elevating consideration of gas prices over all other considerations, the Commission concludes that prudence required Great Plains to manage all relevant considerations—including cost. In this instance, the record demonstrates that Great Plains failed to recognize the unprecedented costs of spot gas that emerged over the holiday weekend, failed to understand the significant risk that those costs would persist on February 17, and failed to take reasonable steps to avoid incurring such costs unnecessarily.

The Commission also respectfully disagrees with the ALJs' conclusion that, because Great Plains was required to make decisions based on rapidly developing information during an unprecedented and complex gas purchasing environment, the Company was absolved of the obligation to furnish service at just and reasonable rates. While the degree of the price spike was unknown when planning for the holiday weekend, by the time Great Plains was making purchasing decisions on February 16, it was clear that the cost of spot gas was so excessive that a prudent utility would actively manage its available resources and make *some* meaningful efforts to mitigate ongoing economic harm to its customers.

The Commission appreciates the importance of considering potential operational issues in gas supply planning. However, in light of the extreme cost of spot gas, the increasing temperatures, and the option to curtail interruptible customers, Great Plains did not meet its burden to justify its decision to focus solely on these concerns in its supply planning for February 17 while affording no meaningful consideration to its obligation to keep rates just and reasonable for customers.

Great Plains has failed to demonstrate that reasonable reliability concerns justified its decision not to maximize its available storage resources on February 17. Had Great Plains prudently planned to fully utilize its available storage supply, it could have avoided purchasing 1,770 Dth of spot gas, which was priced at a daily average of $172.21/Dth. This constitutes an unnecessary and imprudently incurred cost that was not adequately considered in Great Plains' gas planning process.

Similarly, Great Plains has not satisfied its burden to explain and justify that its supply reserve margin of 13% on February 17 was within a reasonable range. By February 16, when Great Plains made its purchasing decisions, it knew that gas prices had reached unprecedented levels, so any unnecessary purchase of spot gas would likely cause financial harm to its customers. The Department's expert credibly and persuasively testified that a supply reserve margin slightly exceeding forecasted load was consistent with the industry, and while no single number would be reasonable for all utilities, it is essential that each utility be able to explain and justify how and why it chose its planned supply reserve margin.

While Great Plains stated it elected to plan for 13% excess supply on February 17 because that level was consistent with the range of margins between forecasted and actual loads that occurred over the previous holiday weekend, the Company did not explain why supply reserves of that magnitude were reasonable or justified when planning for only one day ahead amidst moderating temperatures. By February 16, a prudent gas utility would have understood the extreme cost risk to customers posed by additional spot gas purchases and made *some* effort to reduce its excessive supply reserve margin to avoid purchasing unnecessary spot gas. The Company's decisions appear to have been motivated by reliability concerns, with no consideration of cost impacts to customers. But Great Plains has not demonstrated that the reliability risks the Company could have reasonably anticipated under the circumstances on February 16 were sufficient to justify the reserve margin it used when purchasing spot gas for February 17.

Having concluded that Great Plains did not prove it acted prudently as to storage utilization and a deliberately determined and justified supply reserve margin on February 17, the Commission must calculate the costs incurred because of the Company's imprudence.

The Department calculated a recommended disallowance based on a 2% supply reserve margin. The Commission finds this analysis provides a reasonable basis for calculating a disallowance that reflects Great Plains' imprudently incurred costs. A 2% supply reserve margin is consistent with planning for purchases slightly exceeding projected load, and it is slightly higher than the planned supply reserve margins employed by several gas utilities over the holiday weekend, including Great Plains' own supply reserve margin of 1.8% on February 14. A disallowance calculation based on a 2% reserve margin adequately balances the cost impacts to customers of additional spot gas purchases with ensuring that Great Plains could address potential reliability issues caused by supply cuts or increased demand.

For the reasons stated above, the Commission will disallow $439,635.

VII. Curtailment

A. Introduction

In addition to firm customers who expect uninterrupted service, gas utilities have certain customers who have agreed to potential interruptions in their gas supply in exchange for a lower rate. These interruptible customers typically have alternative fuel or are willing to shut down their gas-dependent operations when the utility calls on them for curtailment.

Great Plains' interruptible service tariffs govern curtailment and outline applicable policies and procedures. Great Plains' tariffs define "curtailment" broadly as "A reduction of transportation or retail natural gas service deemed necessary by the Company."[31]

Other than those operating under grain-drying tariffs, Great Plains did not curtail any of its interruptible customers during the February Event, and it did not utilize curtailment as a price-mitigation tool to reduce spot gas purchases during the February Event.

B. Positions of the Parties

1. The Department

The Department contended that, by February 16, when the magnitude of the price spike was known and there was reason to expect prices would remain high through February 17, prudence required Great Plains to look beyond its typical practices and curtail interruptible load to reduce spot gas purchases to mitigate the price spike's severe financial impact on customers.

The Department argued that both Great Plains' small and large interruptible service tariffs give the Company broad discretion to curtail "whenever, in the 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."[32] The Department explained that the plain language of the tariff gives the Company wide discretion to determine when curtailing interruptible customers may be necessary to protect the interests of firm (non-interruptible) customers. The Department noted that the tariff language does not limit or qualify which "interests" of firm customers may need protecting.

The tariff provision states:

> 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

[31] General Terms and Conditions, Original Sheet No. 6-4 *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGeneralTermsConditions.pdf.

[32] While the corresponding provisions in both the Small and Large Interruptible Gas Sales Tariffs are similar, they contain minor typographical differences that do not appear to impact any party's arguments. *See* Small Interruptible Gas Sales Service Rate 71, Original Sheet No. 5-30 *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas71.pdf ("Customers taking service hereunder agree that the Company, without prior notice, shall have the right to curtail or interrupt such service, 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."); Large Interruptible Gas Sales Service Rate 85, Original Sheet No. 5-50, *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas85.pdf ("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.").

> capacity requirements are otherwise and hereby given preference. The priority of service and allocation of capacity shall be accomplished in accordance with the provisions of the General Terms and Conditions, Section 6, Paragraph V.17.[33]

The Department contended that Great Plains inappropriately relied on the Priority of Service and Allocation of Capacity section of its General Terms and Conditions to argue it is only able to curtail for operational, rather than economic, reasons. The relevant provision states:

> 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.[34]

The Department explained that this language does not address when Great Plains may decide to curtail; it only outlines the default order in which curtailment shall occur absent operational reasons to deviate from that order.

The Department further emphasized the Company's internal email correspondence discussing curtailment authority and argued that these conversations acknowledge the broad authority Great Plains had to curtail under the circumstances that existed on February 16, including a statement that the Company could make the case for curtailments.

Additionally, in its examination of the Company's decisions during the February Event, the Department stated that Great Plains *had* curtailed customers operating under grain-drying tariffs during the February Event. Because sufficient capacity existed to provide service to these

[33] Large Interruptible Gas Sales Service Rate 85, Original Sheet No. 5-50, *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas85.pdf.

[34] General Terms and Conditions, Original Sheet Nos. 6-23 to 6-24, *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGeneralTermsConditions.pdf.

customers, the Department contended that Great Plains' decision to curtail them was inconsistent with its position that curtailment is only permitted for operational reasons.

Based on testimony from King, the Department argued that it would have been prudent to plan to curtail approximately 50% of interruptible load to reduce expensive spot gas purchases while retaining the remaining interruptible load, up to 50%, so it would be available to address any unanticipated issues that could arise on February 17. This approach, the Department explained, would have left 50% of interruptible load (2,930 Dth) available for curtailment in the event of supply cuts. That amount equates to approximately 165% of the amount of storage gas Great Plains reserved. The Department contended that taking this step would have avoided $405,453 in spot gas purchases at the actual average daily cost on February 17.

The OAG supported the Department's analysis and recommendations.

2. Great Plains

Great Plains argued that it did not face any physical constraints that would have justified curtailment during the February Event. Great Plains contended that its tariffs do not allow it to curtail for purely economic reasons and that it has never curtailed for those reasons. Great Plains argued that engaging in the ad hoc economic curtailment proposed by the Department would violate the terms of its tariffs and Minnesota law including the Filed Rate Doctrine.

Great Plains emphasized that the tariffs' references to "capacity requirements" and "system operations" preclude curtailing interruptible customers absent operational issues impacting capacity or system reliability.

Great Plains contended that interpreting its tariffs as granting it broad authority to curtail interruptible customers to protect any interest of firm customers is problematic as it would grant it the authority to engage in any behavior not explicitly prohibited by its tariffs. Furthermore, Great Plains argued that the tariffs' lack of any benchmarks or guidance instructing when economic curtailment is required or reasonable creates unanswered questions that are likely to create confusion within Great Plains and with its customers.

Because it concluded that economic curtailment is not permitted by its tariffs, Great Plains explained that its interruptible customers would not have been on notice that economic curtailment might occur and could not have anticipated it when agreeing to be bound by the interruptible service tariff.

3. Replies

The Department noted that Great Plains' opposition to curtailment based on the Filed Rate Doctrine would only be valid if its tariffs prohibited economic curtailment. As the Department's position is that Great Plains had authority under its tariffs to curtail for economic reasons, it contended that its proposed interpretation of the tariffs does not violate the Filed Rate Doctrine.

Great Plains explained that its grain-drying tariffs require those customers to notify the Company, in advance, when they intend to operate and utilize natural gas service.[35] The Company characterized this notice provision as creating a contractual requirement for these customers to request service, which Great Plains may either approve or deny. It contended that its decision not to let the grain dryers operate during the February Event was justified by the unique usage patterns of those customers and is irrelevant to its authority to curtail customers with higher-priority interruptible service tariffs.[36] However, the Company did not identify any language in its grain-drying tariff granting it greater curtailment authority than is granted in its other interruptible tariffs.

C. Recommendations of the Administrative Law Judges

The ALJs found that Great Plains did not have the authority under its tariffs to curtail for economic reasons. They found that Great Plains acted prudently by not curtailing its interruptible customers during the February Event and, therefore, recommended no disallowance.

The ALJs were particularly persuaded by the Company's past practice of not curtailing for economic reasons. The ALJs found that because Great Plains' tariffs did not expressly address economic curtailment and provided no predefined rules or standards that would apply to notify interruptible customers that their service could be interrupted for economic reasons, the Company was justified in deciding not to curtail.

D. Commission Action

The Commission respectfully disagrees with the ALJs' finding that Great Plains met its burden to prove it acted prudently with respect to curtailment. Great Plains' interruptible service tariffs grant the Company broad discretion to determine when to curtail. Under the broad tariff authority, Great Plains had the latitude to decide to curtail interruptible customers to reduce expensive spot-gas purchases under the circumstances unfolding on February 16 and 17. During such extraordinary circumstances, Great Plains' decision not to curtail was imprudent and caused the utility to incur unreasonable gas costs.

When the Commission interprets obligations under a tariff, it looks first to the specific tariff language. Generally, tariffs are interpreted like any other contract.[37] Words are given their plain

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[35] *See* Interruptible Grain Drying Gas Sales Service Rate, Original Sheet No. 5-33, *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas73.pdf ("Customer will be required to notify Company of the anticipated startup of grain drying operations no later than 10:00 A.M. CST the day before customer starts operating their grain drying facilities. Customer must provide to the Company the location of the grain drying facility, the expected hours of operation, and the total Dk needed for operation of the grain drying facility.").

[36] While the grain-drying tariff is the only interruptible tariff that includes a requirement to notify the Company of anticipated startup of operations, the grain-drying, large interruptible sales, and small interruptible sales tariffs all require customers to notify the Company of anticipated changes in daily operations. *See e.g.*, Large Interruptible Gas Sales Service Rate 85, Original Sheet No. 5-50 at ¶4, *available at* https://www.gpng.com/wp-content/uploads/PDFs/Rates-Tariffs/Minnesota/MNGas85.pdf.

[37] *Info Tel Commc'ns, LLC v. Minnesota Pub. Utils. Comm'n*, 592 N.W.2d 880, 884 (Minn. App. 1999).

and ordinary meaning and viewed in accordance with the tariff as a whole.[38] Any finding of ambiguity must be reasonable and not the result of straining the tariff language.[39]

Great Plains' interruptible tariffs provide it with "the right to curtail or to interrupt whenever, in [the] 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." This grants Great Plains broad authority to rely on its "sole judgment" to determine when "it might be necessary to [curtail] to protect the interest of its [firm] customers." The interest to be protected is neither defined nor qualified other than to state that it must be the interest of customers "whose capacity requirements are otherwise and hereby given preference."

The priority of service and allocation of capacity section in the General Terms and Conditions does not limit Great Plains' broad authority to curtail; it simply designates the order in which curtailment shall occur. It also grants Great Plains the discretion to deviate from the default priority order due to system operational reasons, operational problems on Great Plains' system, and restrictions at a given delivery point or receipt point. While Great Plains' ability to curtail higher-priority customers before curtailing lower-priority customers is limited to addressing operational issues on its system, its authority to curtail is only required to protect customer interest and is not similarly qualified. It was in customers' interest to be protected from incurring unreasonable amounts of historically high spot gas costs. Accordingly, Great Plains had the right under its tariffs to curtail service to interruptible customers on February 17 to advance that customer interest.

Great Plains' proposed interpretation of its tariff language strains the plain language by converting the triggering condition that provides authority for curtailment from the broad "protect the interest of its customers" to a more limited "provide continued service to customers." If the purpose of the interruptible tariff language was to allow Great Plains to curtail only when it has determined that system capacity or system reliability required it, Great Plains should have employed clear tariff language to that effect. It did not.

Despite the broad authority Great Plains had to curtail under its interruptible tariffs' plain language, the Company speculated that its interruptible customers would have been unaware that economic curtailment might occur because specific parameters justifying economic curtailment are not outlined in the tariffs. While its customers may have understood that curtailment has historically occurred when system conditions required it to ensure reliable service to higher-priority customers, Great Plains put forth no evidence that any of its interruptible customers shared Great Plains' overly restrictive interpretation of the Company's curtailment authority. Furthermore, customers operating under interruptible tariffs have voluntarily elected that status to obtain cost savings rather than reliable firm supply. Given that customers electing interruptible tariffs have demonstrated the willingness and ability to periodically not receive gas service in exchange for lower gas rates, some may have willingly curtailed on February 17 to reduce the overall impacts of extraordinarily high gas prices.

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[38] *See Motorsports Racing Plus, Inc. v. Arctic Cat Sales, Inc.*, 666 N.W.2d 320, 323–24 (Minn. 2003).

[39] *Info Tel Commc'ns, LLC*, 592 N.W.2d at 884.

While the Commission recognizes that Great Plains has not historically used curtailment for economic reasons, the Company acknowledged that it had decided not to allow grain dryers to run on February 17, despite the Company's contemporaneous statements that it had sufficient capacity to provide them service. Great Plains explained that it made this decision because of the unique usage patterns of customers operating under the interruptible grain drying service tariff and referenced a tariff provision that requires grain dryers to provide the Company advance notice of their intent to start operations to prevent unexpected increases in load that could overrun the Company's transportation capacity; however, the grain-drying tariff's notice requirements do not provide Great Plains with any additional authority to curtail service to grain dryers beyond that provided in other interruptible tariffs. Great Plains failed to demonstrate how the increased load of allowing grain dryers to operate on February 17—with sufficient capacity, increasing temperatures, and decreasing demand—would have created any of the operational issues the Company argued are necessary to exercise its authority to curtail. This calls into question the Company's judgment in determining how to apply its tariffs.[40] Under the extenuating circumstances, a prudent company would have taken action to curtail interruptible customers to ameliorate *some* degree of costs to ratepayers.

The Commission concurs with the Department that curtailing 50% of Great Plains' interruptible load on February 17 would have reasonably balanced the goals of protecting ratepayers from extreme prices and ensuring system reliability. As a result, the Commission will disallow $405,453 in gas costs.

VIII. Financial Hedging

A. Office of the Attorney General

The OAG contended that Minnesota gas utilities, including Great Plains, acted imprudently by failing to engage in financial hedging practices that could have mitigated or completely offset the extraordinary gas costs incurred during the February Event.

The OAG defined hedging as a tactical action undertaken with the intent of reducing the risk of losing money. The OAG's expert, Brian Lebens, testified that Great Plains should have utilized exchange-traded hedges, customizable over-the-counter products, and hedged swing contracts to avoid the extreme price spikes during the February Event. Lebens provided examples of hedges—including monthly call options and daily swing futures—and analyzed their observed performance in financial markets during the February Event. Lebens theorized that the failure of Great Plains to proactively utilize risk-mitigating practices justifies a disallowance of $950,000 to $1,232,000 of Great Plains' extraordinary costs.

[40] The Commission recognizes the internal discussions at Great Plains on the morning of February 16 demonstrate that its decision makers were exploring options to address a challenging and unprecedented situation and does not find any individual opinion expressed binds the Company to a specific legal interpretation of its tariff language. However, the Commission finds it concerning that these discussions appear to be first occurring several days after Great Plains learned of the magnitude of the February Event price spike. A prudent utility would have been actively exploring all potential options throughout the ongoing February Event and entered February 16 with answers to questions that Great Plains was only then asking.

The OAG explained that the typical cost-recovery mechanism available to utilities to automatically recover gas costs greatly diminishes the incentive to adequately balance potential customer costs in their gas purchasing decisions and encourages utilities to act imprudently in gas planning and purchasing. While significant price spikes have been uncommon and the magnitude of those experienced during the February Event were unprecedented, the OAG contended that because they have occurred in the past, Minnesota's gas utilities had an obligation to implement effective financial hedging strategies that would insulate ratepayers from bearing the financial burden of atypically high gas prices. As utilities are active participants in the complex natural gas markets, the OAG explained that they are uniquely situated to leverage their capabilities to protect their customers during extreme price spikes. While certain types of financial products may not be readily available on the open market, the OAG contended that gas utilities should have negotiated for customized, over-the-counter contracts to mitigate effects of the short-term, extreme price spikes that occurred during the February Event.

Recognizing that utilities had limited options to hedge risks once the market became aware of extreme prices, the OAG explained that the gas utilities should have secured hedging opportunities well in advance of the February Event so that they would have the tools in place to adequately mitigate impacts of extreme prices whenever they might occur. The OAG emphasized that it need not prove the viability of a specific hedging plan that would work for each utility, rather the utilities must demonstrate that their financial hedging practices, or lack thereof, were prudent.

The OAG noted that CenterPoint, MERC, and Xcel are subject to Commission orders that create variances allowing for cost recovery of certain financial hedges under the purchased-gas-adjustment rules, and Great Plains has not sought such a variance; however, the OAG explained that utilities do not need Commission preapproval to engage in prudent financial hedging practices and that PGA-variance orders approve a cost-recovery mechanism not specific hedging strategies.

B. Great Plains

Great Plains argued that that the financial hedging practices recommended by the OAG were not viable to minimize the extraordinary costs it incurred during the February Event.

First, the OAG relied on examples of financial products that are priced at Henry Hub, which is in Louisiana, and Great Plains argued that Henry Hub is too far removed from its distribution network to provide financial products with meaningful potential benefit. Great Plains contended that hedging products based on Henry Hub pricing fail to account for the basis spread that exists when prices differ by hub. Great Plains argued that there are no futures contracts on the Chicago Mercantile Exchange relating to the Ventura or Demarc hubs where Great Plains incurred its most significant February Event costs.[41]

Second, Great Plains stated that Lebens focused on the potential benefits of various financial hedges, but he failed to adequately account for the costs and risks inherent to the hedges he proposed. Specifically, Great Plains noted that while so-called costless collars may allow a

[41] The OAG provided evidence of daily futures swing contracts related to Demarc and Ventura listed on the Intercontinental Exchange.

purchaser to save money during an extreme price spike, they also have the potential to increase costs to a purchaser through obligations to take an overabundance of gas at above-market price. In concluding that the proposed financial products are inherently risky, Great Plains maintained that it was imprudent to engage in the recommended hedging strategies because they carry significant risk of cost increases to customers.

Third, Great Plains explained that the proposed hedges would not have been able to avoid the extraordinary costs incurred during the February Event because their success depends on proper timing informed by hindsight. For example, the exchange-traded hedging contracts correspond to monthly deliveries, so Great Plains contended that it would have needed to execute contracts for February at the end of January when the forecasts indicated February would be warmer than average.

Fourth, Great Plains noted that Lebens testified that he did not consider the relative size of each utility when he made his recommendations. Great Plains emphasized that its relatively small size and scope makes it particularly ill-suited to engage in the speculative hedging techniques recommended by the OAG because some of the potential futures contracts the OAG proposed have minimum purchase quantities of 10,000 MMBTU, which greatly exceeds its daily baseload purchases at Carlton, Demarc, or Emerson.[42]

C. Recommendations of the Administrative Law Judges

The ALJs determined that prudence did not require Great Plains to engage in the hedging strategies advanced by the OAG. The ALJs stated that Great Plains would have needed to engage in the OAG's hedging strategies well in advance of the February Event, and before Great Plains had any knowledge that the February Event would occur. The ALJs found that the OAG's proposals relied on speculation that certain products would have been available and cost-effective, and the illustrative application of the OAG's proposed hedging strategies failed to demonstrate that it would have been prudent or possible for Great Plains to implement them to avoid incurring extraordinary costs during the February Event.

D. Commission Action

The Commission agrees with the OAG that the fact that financial hedging decisions had to be made long before the February Event is not a reason to categorically reject any potential disallowance based on hedging. An action or inaction at any time could support a disallowance if it was imprudent and caused the utility to incur unreasonable costs. When considering a disallowance, there is no theoretical limit on how much time may pass between a relevant imprudent action and the unreasonable cost it causes; rather, the particular facts presented determine whether a sufficient causal relationship exists to support a disallowance.

The Commission also agrees with the OAG that the ALJs overstated the Commission's role in gas utilities' financial hedging activities. Gas utilities do not need prior Commission approval to engage in financial hedging, and the Commission does not pre-determine the prudence of

[42] In its reply, the OAG emphasized that 10,000 MMBTU was a *monthly* minimum quantity, and it contended that these contracted amounts would not create an obligation to take excessive quantities each day as Great Plains argued.

hedging strategies when it determines what type of hedging costs can be recovered through a utility's purchased-gas-adjustment rider or when it approves a gas procurement plan or routine purchased-gas-adjustment filings. The fact that the Commission has not issued an order contemplating proposed financial hedging practices of Great Plains is insufficient to find Great Plains' strategies prudent.

However, on this record, the Commission concurs with the ALJs' conclusion that Great Plains did not act imprudently or incur unnecessary or unreasonable costs by failing to engage in the financial hedging strategies proposed by the OAG.

The OAG's proposed strategies had the potential, if implemented correctly, to mitigate some of the costs Great Plains incurred purchasing expensive daily spot gas when index prices at Demarc and Ventura reached unprecedented highs. While the record demonstrates that certain financial hedges may have allowed gas utilities to avoid incurring some degree of extraordinary costs incurred in the February Event, the Commission agrees with the ALJs' determination that the theoretical examples provided by the OAG are too attenuated from a real-world application of these strategies to provide a reliable justification for any disallowance.

Great Plains demonstrated that it makes efforts to mitigate price risks in its gas planning by seeking geographically diverse supply including targeted levels of baseload and storage that function as physical hedges against unanticipated price spikes. Considering Great Plains' size and circumstances, the Commission finds that Great Plains' decision not to implement financial hedges to potentially mitigate the impacts of an unprecedented price spike was within the range of prudent options.

For these reasons, the Commission declines to disallow recovery of costs related to financial hedging as recommended by the OAG.

IX. Compliance Filings and Final True-Up

The Commission will require Great Plains to recalculate its remaining balance of recoverable extraordinary costs to account for the disallowances ordered herein and, accordingly, update the extraordinary-cost recovery factors for the surcharge for the remainder of the 27-month recovery period. Within 60 days, Great Plains shall provide this updated information in a compliance filing for approval by the Executive Secretary.

Additionally, because the extraordinary-cost surcharges are volumetric and are calculated based on sales forecasts from which actual sales may vary, there may be an outstanding balance of under- or over-recovered costs at the end of the recovery period. To align the amount of recovery with recoverable extraordinary gas costs, the Commission will require Great Plains to incorporate any remaining true-up in the first annual automatic adjustment report following the end of the 27-month recovery period.

X. Prospective Investigation

In addition to precluding utilities from charging ratepayers for past imprudent costs, the Commission will require the affected gas utilities to take action to prevent or reduce impacts of future extreme weather and market events on Minnesota's ratepayers and utilities. As extreme weather events become more frequent due to climate change, it is vital that utilities act to protect ratepayers from reoccurrences similar to the February Event.

To that end, the Commission will require Great Plains to review its practices relating to gas contracting, purchasing, hedging, storage, curtailment, customer communications, and other relevant practices and file a plan explaining how it will improve or modify its practices to protect ratepayers from extraordinary natural gas price spikes in the future.

As a part of its plan, the utility shall identify the general timeframe in which it will implement the modifications. If plan implementation would require modification of tariff language, the utility shall provide proposed tariff language with its plan. Additionally, the utility should include in its filing a discussion of how integrated resource planning could facilitate ratepayer protection from price spikes, and it should identify any statutory or rule changes that could be implemented to protect ratepayers from future price spikes.

Great Plains should also provide an analysis of whether it considered filing a performance-based gas purchasing plan pursuant to Minn. Stat. § 216B.167. If it has chosen not to proceed with a performance-based gas purchasing plan under that section, it should provide an analysis explaining that decision.

Further, the utility should explain how any proposed tariff, rule, or statutory changes are consistent with the Natural Gas Innovation Act, Minn. Stat. §§ 216B.2427 and 216B.2428.

The Commission will require Great Plains to file its plan in Dockets No. G-002/CI-21-235 and G-999/CI-21-135 by September 15, 2022. Reply comments will be due by October 14, 2022. The Commission will hold hearings on the plans on or before December 9, 2022.

The Commission previously contemplated convening a stakeholder group to examine prospective changes in natural gas supply planning. However, based on further discussions and information developed through these proceedings, the Commission has determined that the plan-submission process described above is a more efficient and effective way to pursue the same goals. Accordingly, the Commission will rescind ordering paragraph 26 of the August 30, 2021, order.

ORDER

1. The Commission adopts the Administrative Law Judges' Findings of Fact, Conclusions of Law, and Recommendation to the extent that they are consistent with the Commission's decision as set forth herein.

2. The Commission finds that Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co. (Great Plains) did not meet its burden to prove it acted prudently with respect to storage utilization and supply reserve margin for February 17, 2021, and, therefore, disallows recovery of $439,635.

3. The Commission finds that Great Plains did not meet its burden to prove it acted prudently with respect to curtailment on February 17, 2021, and, therefore, disallows recovery of $405,453.

4. Within 60 days, Great Plains must make a compliance filing that updates the remaining recovery amount and also updates the recovery factors for the remainder of 27-month recovery period. The Commission delegates approval of this compliance filing to the Executive Secretary.

5. Great Plains shall incorporate any remaining true-up into its next annual AAA report following the end of the 27-month period.

6. Great Plains must review its gas contracting, purchasing, hedging, storage, interruptible, customer communications, and other relevant practices and, by September 15, 2022, file a plan in Docket Nos: G-004/M-21-235 and G-999/CI-21-135 on how it will improve or modify its practices to protect ratepayers from extraordinary natural gas price spikes in the future. As part of its plan, the utility shall identify the general timeframe it will implement the modifications, and, if the proposed change requires modification of tariff, proposed tariff language. The utility should also identify, in its filings: a) how integrated resource planning could facilitate ratepayer protection from price spikes; and b) any statutory or rule changes that could be implemented to protect ratepayers from future price spikes. The utility should also provide an analysis of whether it considered filing a plan pursuant to Minn. Stat. § 216B.167 (Performance-Based Gas Purchasing Plan) and its analysis of why they are not using the statute if it has chosen not to proceed with such a plan. The utility should also indicate how any proposed tariff, rule, or statutory changes are consistent with the Natural Gas Innovation Act (Minn. Stat. §§ 216B.2427 and 216B.2428). Reply comments to the utility plans will be due by October 14, 2022. The Commission shall hold hearings on these plans on or before December 9, 2022.

7. The Commission rescinds Order Point 26 of the Commission's August 30, 2021 Order, regarding a stakeholder group, in Dockets 21-135, 21-138, 21-235, 21-610 and 21-611.

8. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Will Seuffert
Executive Secretary

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CERTIFICATE OF SERVICE

I, Chrishna Beard, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
ORDER DISALLOWING RECOVERY OF CERTAIN NATURAL GAS COSTS AND REQUIRING FURTHER ACTION

Docket Number **G-004/M-21-235, G-999/CI-21-135**
Dated this 19th day of October, 2022

/s/ Chrishna Beard

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