BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Petition of Xcel Northern States Power Company d/b/a Xcel Energy to Recover February 2021 Natural Gas Costs	ISSUE DATE: October 19, 2022 DOCKET NO. G-002/CI-21-610
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 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]

[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. (Great Plains).

[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).

II. Purchased-Gas Adjustment

Total annual gas costs are reviewed when utilities file their annual automatic adjustment (AAA) reports by September 1 each year. AAA reports include detailed information about all automatic adjustments 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 through a bill surcharge or refund over the next 12-month billing cycle.[4]

Given the magnitude of costs 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 July 6, 2021, Xcel filed its request for a variance to the Commission's automatic-adjustment rules to modify recovery of an estimated $179 million in extraordinary gas costs incurred during the February Event.[5]

On August 30, 2021, the Commission issued an order granting a rule variance and approving a special surcharge to recover the extraordinary gas costs over an extended period using a seasonally adjusted schedule. This action 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.[6]

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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[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] *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, Joint Comments of the Gas Utilities, and Xcel's Initial Comments—Request for Recovery (July 6, 2021).

[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). The Commission originally ordered recovery over 27 months, but it extended the recovery period for Xcel's residential customers to 63 months in a subsequent order. *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy's Petition for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-002/GR-21-678, Order Setting Interim Rates, at 6, Ordering Para. 10 (December 30, 2021).

[7] Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing, at 20, Ordering Para. 3 (August 30, 2021). 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.

Applying the Commission's definitions, Xcel requested to recover through the February-Event surcharge a total of $178,978,695 in extraordinary gas costs.

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 that 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 (ALJs) 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);
- 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.

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.

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

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

[10] *Id.*

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

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.[12]

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.[13] Any doubt as to reasonableness is to be resolved in favor of the consumer.[14] There is no burden on agencies or other intervenors to precisely identify which imprudent actions caused which costs in order to justify a disallowance.[15] 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.[16]

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. Prudence 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.

II. The Administrative Law Judges' Report

Two ALJs presided over joint contested-case proceedings on the four utility-specific investigations. They held three days of evidentiary hearings and two public hearings. They reviewed the testimony of expert witnesses and examined exhibits. In the ALJ Report on Xcel's

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[12] Minn. R. 7825.2390.

[13] Minn. Stat. § 216B.16, subd. 4.

[14] Minn. Stat. § 216B.03.

[15] *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).

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

February Event costs, the ALJs made more than 300 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 the ALJs' 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 affected 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 commenters 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.[17] 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. Background on Gas Purchasing During the February Event

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

Minnesota gas utilities purchase natural gas from various gas-producing regions and transport that gas via pipeline to serve their customers in Minnesota. Gas purchases can be made for baseload (on a monthly or seasonal basis) or on the daily spot market. The primary trading hubs for the affected Minnesota gas utilities are Ventura (in Iowa), Demarc (in Kansas), and Emerson (at the U.S.-Canada border near North Dakota). Xcel also buys gas at the Chicago hub.

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[17] Minn. R. 7829.2390.

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.

Most of the extraordinary gas costs at issue in this order came from purchases made on the daily spot market on two occasions.

First, on the morning of Friday, February 12, 2021, Xcel purchased gas on the daily spot market 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. Xcel was required to purchase the same volume of gas for each of these four days. Accordingly, it determined the volume of spot gas to purchase for each day of the February 13–16 period based on its projected needs for the coldest of the four days, which was February 14.

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

Gas may be purchased on the daily spot market at a "firm" price agreed upon between a buyer and a seller, or at the "index" price, which is an average of the firm transactions for that purchasing period at each hub. During the February Event, Xcel primarily purchased spot gas at the index price, but it also made some fixed-price purchases. During the February 13–16 period, index prices reached $154.9/Dth at Ventura, $231.7/Dth at Demarc, $129.8/Dth at Chicago, and $6.2/Dth at Emerson.[18] For February 17, index prices landed at $188.3/Dth at Ventura, $133.6/Dth at Demarc, $22.1/Dth at Chicago, and $10.1/Dth at Emerson.

In addition to baseload supply and daily spot market purchases, gas utilities have various tools they can use to provide price stability and ensure reliability. These tools include interruptible service agreements, gas storage, peak-shaving facilities, and financial hedging.

Interruptible service agreements allow a utility to call on customers to temporarily curtail their gas usage. Customers may choose to accept such terms in exchange for lower rates.

Storage entails maintaining a reserve of gas purchased at lower rates outside the heating season to be drawn on when commodity prices are higher.

Peak-shaving plants help a utility to maintain reliable service to firm customers (i.e., non-interruptible customers) on relatively rare occasions—for example, when capacity needs exceed contracted pipeline capacity or when fluctuations in load or supply require additional gas—by supplementing the utility's supply with propane or liquid natural gas.

[18] For comparison, the index price at Demarc was as low as $2.5/Dth at the beginning of February 2021. Prior to the February Event, the Ventura hub had only ever priced gas above $10/Dth in the winters of 2013–14, 2014–15, and 2017–18. The previous record-high index price at Ventura was approximately $65/Dth for the three-day delivery period of December 29–31, 2017, during a short-term price spike related to extreme cold weather that occurred over a holiday weekend.

Financial hedging is an action taken to reduce the risk of financial loss, often by using a financial derivative such as an option or futures contract to offset the risk of price movement in a related physical transaction.

Parties recommending disallowances in this case contended that Xcel imprudently purchased excessive volumes of gas on the daily spot market at extremely high prices during the February Event as a result of the utility's imprudent actions relating to peak-shaving plants, storage, curtailment, load forecasting, procuring monthly baseload supply, and financial hedging.

VI. Baseload Purchases

A. Introduction

At the end of each month, Xcel purchases "baseload" gas for the next month, committing to take a fixed volume of gas each day at a fixed price. Baseload gas purchases tend to promote price stability because their prices ordinarily are set at the first-of-the-month published index price, whereas daily spot-market prices fluctuate over the course of the month. Purchasers of baseload gas must accept delivery of the daily contracted quantity every day, even if baseload purchases exceed customer demand.

Xcel's baseload planning takes into account the utility's minimum-load forecast for the month, prevailing and historical market conditions, the weather forecast, Xcel's storage inventory, the inventory levels it needs to have remaining at the end of the month, and the price of available storage inventories compared to the price of available baseload supplies. In developing its minimum-load forecast for a given month, Xcel considers how much gas customers consumed during that month in the preceding five years.

For the month of February 2021, Xcel had to secure its baseload supply by January 28, 2021.

B. Positions of the Parties

1. The Department

The Department contended that Xcel imprudently under-purchased baseload gas for February 2021, unreasonably exposing customers to additional risk of high spot-market prices and ultimately causing the utility to spend an extra $17,040,342 on gas.

The Department asserted that Xcel underpurchased baseload gas as a result of two imprudent decisions. First, Xcel developed an unreasonably low forecast of the minimum amount of gas it would need to serve customers on the lowest-load day in February. Then, it unreasonably failed to procure enough baseload supply to even meet the needs projected by that low forecast.

According to the Department, Xcel's opaque explanation—that it develops the forecast by considering data for that month from the preceding five years—failed to establish the reasonableness of the utility's minimum-load-forecast methodology. However, the Department noted that Xcel's minimum daily load forecast for February 2021 was only 10 Dth above the utility's minimum daily load for February from the preceding five years. The Department contended that Xcel's method, which essentially sets the lowest five-year historical data point as the assumed minimum daily load for the coming month, is unreasonable.

The Department further contended that, even according to Xcel's unreasonably low minimum load forecast, the utility procured insufficient baseload supply to serve the minimum expected daily customer requirements for the month. Xcel's forecasted minimum load for February 2021 was 189,763 Dth per day. However, contrary to its stated goal of meeting the minimum daily load requirement with baseload supply, Xcel procured only 168,600 Dth per day of baseload gas for the month. The Department argued that procuring 21,163 Dth less than the forecasted minimum requirement was an imprudent deviation from Xcel's established practice.

The Department's expert witness, Matthew King, calculated a proposed disallowance based on the incremental costs Xcel would have saved if it had purchased enough additional baseload gas to meet its forecasted minimum daily load and reduced its spot-gas purchases during the February Event by a commensurate amount. He applied the average daily index price at the Ventura hub over the February Event ($161.59/Dth) to the volume of gas Xcel could have avoided purchasing on the spot market (21,163 Dth per day), and then offset those savings by the cost of the additional baseload gas the utility would have purchased (at $2.74/Dth) under this strategy. King concluded that this approach would have saved Xcel's customers approximately $17.04 million during the February Event.

The Department calculated its proposed disallowances for Xcel based on index prices at the Ventura hub—which had the highest index price of all the hubs on February 17 and the second-highest, after Demarc, over the February 13–16 period—rather than using an average of the spot-market prices Xcel paid across all hubs. Xcel had greater geographic diversity of supply options than the other affected utilities, so it was able to procure some supply at the Emerson and Chicago hubs, where prices remained much lower over the February Event. The Department maintained that prudence would have required Xcel to take advantage of its access to lower-priced supply options by reducing the volumes of gas it purchased at higher index prices first; it would not have been reasonable to reduce the volumes of gas purchased at lower prices while maintaining transactions at more expensive hubs. Therefore, the Department asserted that calculations of costs that Xcel could have avoided through prudent conduct—i.e., the disallowances—should reflect Ventura index prices, not the lower prices at other hubs.

Based on this analysis, the Department contended that $17.04 million of Xcel's February Event gas costs were incurred due to the utility's imprudent under-procurement of baseload supply and, therefore, it would not be just and reasonable for Xcel to recover that amount from customers.

The OAG supported the Department's proposed disallowance.

2. Xcel

Xcel argued that it made prudent baseload gas purchases for February 2021 based on the information that was available when the utility needed to make final baseload purchasing decisions on January 28. Xcel stated that it developed its minimum-load forecast and planned its baseload purchases for February consistent with its usual methodology described above.

Xcel disputed the Department's assertion that Xcel's February 2021 baseload purchasing decisions were inconsistent with the utility's established strategy. While the Department focused on a single factor—the minimum-load forecast—Xcel explained that it considers all relevant factors in making supply planning decisions. For February 2021, Xcel's decision to purchase less baseload gas than its forecasted lowest daily load requirement was premised on recent and expected market conditions, weather patterns, and storage inventory considerations.

Xcel presented evidence that, leading into February, daily spot-market prices had generally been equal to or lower than the first-of-the-month baseload price, meaning spot-gas purchases historically had provided cost savings compared to baseload purchases. And as of January 28, there were no known unusual market conditions indicating a likely reversal of that trend.

Xcel also argued that, as of January 28, the winter had been warmer than usual and forecasts were not yet predicting the duration or geographic scope of extremely cold weather that ultimately occurred two weeks later, so there was no reason to anticipate supply issues or sharp increases in demand and spot-market prices at that time.

Based on these circumstances as understood on January 28, Xcel argued that it had no reason to believe that fulfilling a greater percentage of its forecasted supply needs with baseload gas would save customers money in February.

Further, Xcel stated that it had higher-than-planned levels of storage gas inventory at the end of January—partly due to the relatively warm heating season experienced up to that point—and it needed to make significant storage withdrawals throughout February to meet its maximum storage inventory limits by the end of the month and the season to avoid financial penalties. Accordingly, Xcel planned to use more storage gas in February as a substitute for incremental baseload quantities.

Xcel noted that this strategy was also expected to have the benefit of providing added flexibility to respond to varying weather and market conditions on a daily basis. The utility could withdraw different volumes of gas from storage each day, while baseload purchases commit the buyer to take a fixed volume of gas every day of the month. Moreover, the storage resources available to Xcel for February (at $1.89/Dth) were less expensive than the cost of purchasing additional baseload gas (at approximately $2.75/Dth).

Xcel's expert witness, Steven Levine, testified that it is reasonable to take storage inventory into account when evaluating baseload gas needs, and he cited examples of other utilities that do so. Levine opined that the baseload volume Xcel chose for February 2021 was reasonable in light of the storage inventory considerations and the pricing information known at the time.

In addition to the cost and storage considerations influencing Xcel's decision to purchase less baseload gas, Xcel contended that buying more baseload gas than is ultimately necessary can lead to operational issues that, over time, outweigh any potential benefit of buying additional baseload gas. Baseload purchases require the utility to take possession of the full contracted quantity each day regardless of actual load. If a utility takes gas in excess of demand, it must either place the excess gas in storage (which is not always possible due to capacity and pressure constraints), attempt to resell it on the market (potentially at a loss), or pay pipeline penalties.

For these reasons, Xcel argued that its baseload supply purchasing decisions for February 2021 were prudent and do not warrant any disallowance.

3. The Department's Reply

In response to Xcel's contention that it planned to use more storage gas as a substitute for baseload, the Department argued that both sources are needed because they fill different roles—storage being a flexible resource and baseload being fixed—so it is unreasonable to procure too little of one in reliance on a plan to substitute with the other.

The Department also disputed Xcel's assertion that it needed to purchase less baseload supply to withdraw enough storage gas to meet required inventory levels by the end of the month, maintaining that the additional storage withdrawals should have displaced daily spot-gas purchases rather than price-stable baseload purchases. The Department stated that reducing baseload supply to allow for greater storage withdrawals unreasonably and unnecessarily exposed Xcel's customers to more risk of price volatility by necessitating additional purchases in the daily spot market.

C. Recommendation of the Administrative Law Judges

The ALJs found Xcel's baseload-procurement strategy prudent and recommended no disallowance. Given that baseload purchases committed Xcel to take the same amount of gas every day of the month regardless of actual load, the ALJs found that it was reasonable for Xcel to identify a minimum-load figure based on the lowest daily demand for that month during the previous five years and to ultimately purchase less than that forecasted minimum volume based on other relevant factors.

The ALJs rejected the Department's rigid position that a utility must always purchase exactly enough gas to meet its forecasted minimum daily load for the month. Rather, they found that Xcel reasonably based its baseload-purchasing decisions on prudent considerations of all the factors discussed above. The ALJs also found that, at the time Xcel had to make final baseload-purchasing decisions, Xcel had no reason to expect that procuring more baseload gas would save money or otherwise benefit customers.

D. Commission Action

The Commission concurs with the ALJs that Xcel's baseload-procurement decisions for February 2021 were reasonable.

The optimal level of baseload gas to purchase is a fact-specific question that depends on the circumstances. Given the inherent limitations of minimum-load forecasts and the multiple factors that may cause customer loads to vary from historical data in any given month, the Commission is not persuaded that strictly equating baseload purchases to a single forecasted lowest-daily-requirement number, as suggested by the Department, was the only prudent option.

To the contrary, Xcel persuasively established the prudence of both its general strategy of considering multiple relevant factors when determining its baseload-gas needs and its application of that strategy to the facts that existed as of January 28, 2021. In particular, Xcel reasonably considered the fact that it would need to make significant storage withdrawals in February to meet contractual obligations and avoid financial penalties, and at the time, there was no clear indication that market conditions would change such that Xcel should have expected net cost savings from purchasing greater baseload supply for the month.

The Commission therefore declines to disallow recovery of any extraordinary gas costs as a result of Xcel's procurement of baseload gas supply for February 2021.

VII. Short-Term Load Forecasting

A. Introduction

Xcel begins the process of gas supply planning by developing a forecast of load, or the total amount of gas it expects its customers to require, in a given period. Utilities rely on load forecasts to help them determine how much gas to purchase with the dual goals of ensuring sufficient supply to meet customers' needs while avoiding acquiring unreasonable amounts of excess gas. Unreasonable load forecasting could lead a utility to procure insufficient supply, which could impede the utility's ability to maintain continuous, reliable service to customers, or to procure unreasonably high volumes of gas, which could result in unreasonable rates.

Xcel uses a system called TESLA, which forecasts customer loads based on a linear regression model using weather forecasts and past load data. Xcel describes TESLA as a "learning model," meaning it calibrates load forecasts based on recent actual load data.

Xcel used daily load forecasts to inform its spot-market purchasing decisions on February 12 (for gas to be delivered February 13–16) and on February 16 (for delivery on February 17).

The following table compares Xcel's TESLA-forecasted load and its total planned supplies (including daily spot purchases, prior baseload purchases, delivered supply, planned curtailment, and planned storage withdrawals) for each day of the February Event.

Table 1: Xcel's Planned Supplies, Forecasted Loads, and Actual Loads for Natural Gas Customers in Minnesota and North Dakota

	Saturday, Feb. 13	Sunday, Feb. 14	Monday, Feb. 15	Tuesday, Feb. 16	Wednesday, Feb. 17
Planned Supplies (Dth)	752,940	766,354	727,975	740,523	655,946
Forecasted Load (Dth)	729,191	754,477	724,738	674,779	644,628
Percent Planned Supplies Exceeded Forecasted Load	3.3%	1.8%	0.4%	9.7%	1.8%
Actual Load (Dth)	702,070	710,041	683,676	614,091	574,135
Percent Actual Load Exceeded Forecasted Load	3.9%	6.3%	6.0%	9.9%	12.3%

B. Positions of the Parties

1. The Department

The Department contended that the large discrepancies between Xcel's forecasted load and actual load (referred to as "forecasting error") on February 14 and 17 resulted from imprudent load-forecasting methods.[19] The Department recommended three disallowances, representing

[19] The parties focused on February 14 (and not February 13, 15, and 16) because daily spot gas needs for February 14 dictated the volumes purchased for each day of the February 13–16 period. Because the market required uniform-volume daily purchases over the holiday weekend, utilities had to purchase

unreasonable gas costs incurred due to (1) imprudent load forecasting for February 13–16, (2) imprudent load-forecasting for February 17, and (3) additional imprudence causing Xcel to have so much excess gas that it was able to release some interruptible customers from curtailment ahead of schedule on February 17.

With respect to the first two alleged errors, the Department's principal arguments were that Xcel had not met its burden to demonstrate (1) that its load-forecasting methodology adequately accounted for planned curtailments and (2) that the gas it purchased in excess of expected non-curtailed load represented a reasonable supply reserve margin.

a. Accounting for Curtailment in Load Forecasting

One fault the Department identified in Xcel's load forecasting was that it did not reduce the total load to account for planned curtailment.

Leading into the February Event, Xcel decided to curtail all of its interruptible gas customers from February 12 at 11:00 a.m. through February 18 at 9:00 a.m. This curtailment order significantly reduced the total amount of gas Xcel needed during the February Event. However, the Department contended that Xcel failed to incorporate this planned curtailment into its load-forecasting model, thus generating high load forecasts that led Xcel to needlessly purchase expensive gas on the spot market to serve curtailed customers who would not be using any gas.

Although Xcel generally claimed that the TESLA model effectively adjusts for curtailment by learning from data on historical loads that have been affected by past curtailments, the Department contended that it was unreasonable to assume the model would accurately predict the amount of curtailed load for a particular day—at least without more specific information about how the model adjusts based on past data and how the forecasts at issue in this case account for the full planned curtailment, which Xcel did not provide.

To reflect Xcel's planned curtailed load, the Department contended that Xcel should have reduced its TESLA results by 60,000 Dth on February 14 and by 40,000 Dth on February 17,[20] and based its supply planning on these adjusted forecasts of daily non-curtailed load.

b. Supply Reserve Margins

The Department also disputed Xcel's assertion that all the gas purchased in excess of its forecasted load is attributable to the utility's plan to have a prudent reserve of supply available in case of higher-than-expected load, supply cuts, failed deliveries, or other reliability issues. The Department acknowledged that it is reasonable to plan for supply that slightly exceeds expected

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enough gas to meet customer needs on February 14, the highest-load day, and purchase that same volume for February 13, 15, and 16. Thus, an excessive load forecast for February 14 would have caused excess gas purchases throughout the four-day period, while over-forecasting for the lower-load days would not be expected to cause the utility to purchase additional volumes of gas on the spot market.

[20] These numbers are rounded-down approximations of the curtailed-load estimates Xcel provided in response to an information request (61,806 Dth on February 14 and 43,095 Dth on February 17).

load (a supply reserve margin) to reduce the risk of having insufficient supply, but it asserted that the size of a utility's supply reserve margin should be deliberately determined and explainable.

According to the Department, Xcel refused to quantify a reasonable reserve margin or explain specifically how it decides how much gas to purchase in excess of its forecasted load. Xcel generally averred that different circumstances prompt the utility to plan for different amounts of supply, but it did not identify any measurable benchmarks for evaluating the reasonableness of a particular reserve margin.

The Department argued that accepting Xcel's position that its excess gas purchases are entirely attributable to a supply reserve margin, without requiring the utility to explain its reasons for choosing that specific reserve margin, would effectively grant utilities unfettered discretion to purchase supply in excess of anticipated load and pass the costs on to ratepayers.

To determine a disallowance based on the costs Xcel should have avoided by using a reasonable reserve margin, the Department first analyzed possible reserve margins. As examples, it looked to the testimony of three other Minnesota gas utilities, each of which planned for a reserve margin of 1.7% or 1.8% for February 14. Based on its examination of this data, the Department reasoned that using a slightly higher margin of 2.0% would have been reasonable for Xcel under the circumstances.

Although Xcel's calculations showed that its total planned supply exceeded its TESLA load forecasts by only 1.8% on February 14 and 17, the Department countered that reducing the forecasts to account for 60,000 and 40,000 Dth of planned curtailed load, as discussed above, reveals much larger reserve margins of about 10.3% and 8.5%, the reasonableness of which Xcel has not demonstrated.

c. Disallowance Calculations

To calculate disallowance amounts, the Department's expert witness first considered the volume of gas Xcel should have planned for when making purchasing decisions on February 12 and 16 based on the TESLA load forecast, plus a 2% supply reserve margin, less offsets for planned curtailed loads of 60,000 Dth for February 14 and 40,000 Dth for February 17. From there, King determined the amount that should have been purchased on the spot market after accounting for supply from baseload and storage.[21] The difference between that amount and Xcel's actual purchased volumes of spot gas represents the incremental volume of spot gas purchased because of Xcel's unreasonable load forecasting.

King applied the Ventura index prices for those days to the incremental gas volume calculated above to quantify the gas costs attributable to Xcel's imprudent short-term load forecasting.

Based on King's analysis, the Department claimed that Xcel would have avoided $26,875,063 in gas costs if it had used prudent load-forecasting methods for February 14 and reduced its February 13–16 spot-market purchases accordingly.

[21] Because of the market's ratable requirement, purchased spot-market gas volumes for each day of the February 13–16 period had to match the volume needed for February 14, the highest-load day.

Based on a similar analysis, the Department recommended an additional disallowance of $4,351,593, representing gas costs Xcel should have avoided on February 17 through prudent load forecasting and spot-gas-purchasing decisions.

The Department also recommended an additional $2,824,800 disallowance for February 17, arguing that Xcel's ability to end its planned curtailment early that day for some customers is evidence of an even greater degree of over-forecasting and over-purchasing than was captured by the above analyses. It argued that if Xcel had properly accounted for its curtailment plans and used a reasonable reserve margin when purchasing spot-market gas for February 17, it would not have ended up with so much extra gas supply that it deemed it appropriate to terminate its curtailment order half a day early. The Department argued that unreasonable over-forecasting led Xcel to spend an extra $2,824,800 purchasing expensive spot gas for these interruptible customers before February 17, despite the fact that it should not have had enough supply to allow them to resume using gas that day.

2. CUB

CUB also took the position that Xcel did not meet its burden to prove that the substantial discrepancies between its forecasted and actual loads on February 14 and 17 resulted from prudent load forecasting. Unlike the Department, however, CUB tied its load-forecasting argument to an issue of prudent utilization of stored gas, contending that Xcel's over-forecasting led the utility to purchase excessive volumes of gas on the spot market, which in turn impeded its ability to prudently use available storage inventory to mitigate costs during the February Event.

CUB proposed alternative disallowance amounts based on the costs Xcel would have avoided if its load forecasting and reserve margins had led to total planned supplies that more closely matched actual load, either throughout the February Event or on February 17 only.

a. Effect of Imprudent Load Forecasting on Storage Utilization

CUB contended that Xcel engaged in unreasonable load forecasting, causing it to purchase unnecessary volumes of spot gas at extraordinary prices and, in turn, preventing it from maximizing its stored gas resources to mitigate costs.

Gas storage facilities act as hedges against fluctuating gas prices by allowing the purchase of gas at lower prices outside the heating season to be drawn on when commodity prices are higher. Xcel obtains stored gas through long-term contracts with third parties that limit withdrawal volumes on daily, monthly, and seasonal bases. On a given day, Xcel must balance the volume of gas used by customers against the combined flow of baseload deliveries, storage withdrawals, and spot-gas deliveries; if the utility does not achieve this balance, the pipeline will assess imbalance penalties. Accordingly, when total volumes of baseload gas, spot gas, and nominated storage gas exceed actual demand at the end of the day, Xcel prioritizes using the spot-market gas and returns the unused storage gas to its storage account for balancing purposes.

Xcel initially planned to withdraw its maximum daily allowances from storage on February 14 and 17, but the balancing process described above led it to reduce its storage withdrawals by 18% on February 14 and 22% on February 17. In CUB's view, because of this balancing function, Xcel's imprudent load forecasting put the utility in the position of having to hold inexpensive storage gas for future use while distributing excessive volumes of historically costly spot gas to customers amid an extreme price spike to avoid penalties.

CUB argued that, if Xcel had more accurately forecasted demand during the February Event, it could have better utilized stored gas purchased at substantially lower prices, thereby reducing expensive spot-market purchases and avoiding millions in extraordinary gas costs.

b. Accounting for Curtailment in Load Forecasting and Reserve Margins

Like the Department, CUB contended that Xcel's load-forecasting system unreasonably included delivery to interruptible customers despite Xcel's plan to fully curtail throughout the February Event. Thus, CUB argued, Xcel's claim that its planned supply for February 14 and 17 exceeded the TESLA-forecasted load only by a reserve margin of 1.8% was based on a false assumption that interruptible customers would demand gas at their ordinary non-curtailed levels.

CUB's expert witness, Bradley Cebulko, reduced the TESLA load forecasts by Xcel's estimated curtailed loads (61,806 Dth on February 14 and 43,095 Dth on February 17) and recalculated the reserve margins based on these revised load forecasts. Cebulko concluded that Xcel's total planned supply exceeded the utility's forecasted non-curtailed load by 10.6% on February 14 and by 9.0% on February 17.

Although Xcel characterized the difference between its expected load and its planned supply as prudent supply reserve margins, CUB argued that Xcel failed to support the reasonableness of its reserve margins.

c. Disallowance Calculations

CUB requested historical load-forecast and actual-load data from affected utilities to help it determine the degree to which Xcel's February-Event load-forecasting errors are inconsistent with typical levels and to assess what would be a typical forecasting error for Xcel under similar circumstances. Because Xcel declined to provide the requested data, CUB considered data provided by another Minnesota gas utility. Based on his analysis of this data, CUB's expert determined that it is unusual to over-project load by more than 5%.

Cebulko calculated possible disallowances based on the gas costs Xcel would have avoided during the February Event had it achieved a forecasting error of 5%. As an alternative, he also calculated possible disallowances that assumed that a forecasting error of 10% would be acceptable.

Based on Cebulko's analysis and a second expert's opinion that a disallowance based on a 5% load-forecasting error was reasonable, CUB recommended that the Commission disallow $9,734,465 in extraordinary gas costs. CUB contended that this amount represents gas costs Xcel would have avoided if it had used reasonable load-forecasting and reserve margins yielding a forecasting error no greater than 5% for February 14 and 17 (compared to Xcel's actual forecasts of 6.3% and 12.3% over actual load).

Alternatively, if the Commission were to find Xcel's February 14 forecasting error reasonable under the circumstances that existed leading into the four-day period, but also find that Xcel should have forecasted load within a 5% error rate for February 17 based on the circumstances known by February 16, then CUB would recommend disallowing $4,836,910. CUB asserted that this number represents the gas costs Xcel would have avoided if its load forecast had been only 5% above actual load for February 17.

3. OAG

The OAG recommended that the Commission find Xcel's short-term load forecasting was imprudent and argued that any of the disallowances proposed by the Department or CUB had sufficient record support.

4. Xcel

Xcel contended that it used reasonable load-forecasting methods and made prudent spot-market gas purchases on February 12 and 16 based on its daily load forecasts and other relevant factors.

a. Accounting for Curtailment in Load Forecasting

Xcel disputed assertions that the TESLA model does not reduce load forecasts to account for curtailment. Although the utility does not specifically remove planned curtailed loads from its inputs into the TESLA system, the TESLA model incorporates into its regression-based forecast recent actual load data, which includes past loads that have been reduced by curtailment. Xcel argued that this incorporation of past loads into the model yields an adequate estimate of non-curtailed load.

Additionally, Xcel contended that its gas supply planners considered the availability of curtailment independent of the TESLA result when making their purchasing decisions. One Xcel witness testified that the utility purchased less gas than it otherwise would have—effectively reducing the planned reserve margin—based on the utility's plan to curtail interruptible customers throughout the February Event.

Xcel argued that the Department and CUB offered no evidence that their suggested approach—using a mathematical formula to subtract an estimated amount of curtailed load from the TESLA forecast—is commonly used or deemed necessary by industry experts. To the contrary, Xcel's expert testified that Xcel's model is reasonable and that the Department's and CUB's recommended approach to would have created risks of insufficient supply.

b. Supply Reserve Margins

Xcel argued that the volumes of gas it planned to procure in excess of daily load forecasts were prudent reserve margins designed to protect customers from the risks of insufficient supply.

Xcel stated that it is impossible to identify one reserve margin that is reasonable under all circumstances or to distill this multifaceted decision-making process into a generally applicable formula. Rather, reasonable reserve margins vary depending on the weather and load forecasts, time of year, storage inventories, potential for supply failures, interstate pipeline operating conditions, local distribution company conditions, the likelihood of colder-than-forecasted temperatures, whether upstream pipelines have declared balancing penalties, and the market availability of additional gas supply. Additionally, Xcel asserted that reserve margins may be informed by the length and extent of the predicated cold weather, as it is often beneficial to acquire extra gas supply at the beginning of an extended cold weather event.

Xcel argued that, when planning spot-market gas purchases for February 13–16, it was aware of several factors making it prudent to plan for a greater supply reserve margin. It knew there would be high demand in the spot market based on the weather forecasts and the holiday weekend ahead, it knew it would have limited ability to supplement gas supply after that morning because trading platforms would be unavailable over the holiday weekend, it knew freeze-offs were occurring in some production areas, and it knew based on industry experience that significant gas supply disruptions and delivery failures were legitimate concerns over the long weekend.

Additionally, the Northern Natural Gas (NNG) pipeline had called a system overrun limitation, meaning the pipeline would allow no tolerance for gas utilities to be short on balancing gas supply deliveries against actual daily demand. This presented a risk of pipeline imbalance penalties equal to three times the daily spot price if Xcel under-procured gas supply, adding additional reason to avoid falling short on supply over the four-day period.

For February 17, Xcel asserted that its decisions about the reserve margin and spot-market purchasing were influenced by warming trends in the weather forecast over the next few days; continuing concerns about supply failures; the utility's experience-based expectation that lingering market-volatility fears would cause prices to start higher but then drop as the trading cycle progressed that day; and the knowledge that, on February 16, Xcel needed to purchase spot-market gas only for the next day.

Based on these considerations, Xcel contended that the reserve margins it planned for the February Event, and all resulting gas costs, were reasonable.

Xcel argued that the Department's proposal to base disallowances on a static reserve margin of 2%, and CUB's proposal to base disallowances on a 5% forecasting error, were unreasonable because they relied on oversimplified math and were not grounded in the witnesses' personal experience or industry best practices. Xcel further argued that CUB's proposal to base a disallowance on forecasting error rather than reserve margin is unreasonable because the former considers *actual* load—a subsequent fact that the utility could not have known when it was making the decisions at issue—rather than forecasted load.

Further, based on the opinions of two expert witnesses, Xcel argued that establishing any target level of reserve gas supplies on a prospective basis could threaten reliability (if the target is too low) or add costs (if the target is too high). Instead, utilities should have flexibility to determine appropriate reserve margins based on the unique facts surrounding each planning decision.

c. Effect of Load-Forecasting Errors on Storage Utilization

In response to CUB's assertion that Xcel's over-forecasting prevented the prudent use of storage gas, Xcel contended that it planned to withdraw the maximum allowed storage volumes on each day of the February Event and reduced its daily spot-market purchases accordingly. Although Xcel ended up possessing more gas than it needed and, therefore, returned unused volumes to its storage account to balance flowing supplies with actual demand, Xcel argued that this result (1) did not affect its spot-market purchases, which were locked in at least the day before actual demand levels were known; and (2) enabled the utility to avoid substantial imbalance penalties.

Xcel contended that CUB's effort to deem Xcel's load forecasts unreasonably high based on the subsequent fact that customers did not fully consume the nominated storage volumes entails an impermissible application of hindsight to judge the utility's actions based on information it could not have known when it was making the decisions at issue.

C. Recommendation of the Administrative Law Judges

The ALJs found that Xcel's load forecasting and supply reserve margins were reasonable under the circumstances and recommended no disallowance.

The ALJs found that Xcel prudently determined the volume of spot-market gas to purchase for February 13–16 based on a reasonable reserve margin above its TESLA load forecast for February 14, considering the circumstances known on the morning of February 12. Relevant circumstances included forecasted extremely cold temperatures, the supply disruptions already experienced and the potential for further supply and delivery issues, and concerns about risks to human life and property that could result if Xcel procured insufficient gas supply to maintain continuous service.

Additionally, the fact that Xcel had to plan four days in advance knowing it would have limited opportunities to procure additional supply over the long weekend, combined with system overrun limitations posing high pipeline imbalance penalties, made it reasonable for Xcel, on February 12, to plan for relatively high reserve margins over the four-day period.

The ALJs also found that Xcel's short-term load forecasting for February 17 was reasonable based on the TESLA result and a reserve margin that was prudent based on the circumstances known as of February 16.

Additionally, the ALJs rejected the Department's additional recommended disallowance of $2.82 million tied to the early release of curtailed customers on February 17. Concluding that the TESLA model adequately accounted for curtailments, the ALJs did not find that the early release of curtailed customers suggested that Xcel's load forecast was unreasonable.

D. Commission Action

1. Load Forecasting for February 13–16

The Commission concurs with the ALJs that Xcel met its burden to show that its short-term load forecasting and reserve margin planning for February 14 fell within the range of reasonable conduct under the circumstances and did not result in unreasonable gas costs for February 13–16.

The Commission agrees with the Department and CUB that Xcel did not satisfactorily show that the TESLA model adequately accounted for Xcel's planned curtailments in its daily load forecasts. Xcel offered only nonspecific statements that the model learns from past load data and, therefore, future load forecasts must be influenced by past curtailed loads. But Xcel failed to provide sufficient details to explain how this process works or how the influence of curtailments in past load data actually manifested in the February-Event load-forecast results. The explanation Xcel provided does not establish that the TESLA results adequately accounted for Xcel's February Event curtailment plans.

Accordingly, the Commission agrees with the Department that Xcel's total planned supply exceeded the utility's forecasted *non-curtailed* load by approximately 10.3% for February 14 and 8.5% for February 17, not by 1.8% for both days as Xcel's calculations suggested.

However, even assuming that the TESLA forecast for February 14 erroneously included curtailed load, the record contains substantial evidence that Xcel's gas supply planning for February 14 entailed prudent consideration of multiple other relevant factors in conjunction with the load forecast such that, under the totality of the circumstances, Xcel's load forecasting and reserve margin for February 14 did not cause Xcel to incur unreasonable gas costs.

That is, even after reducing Xcel's TESLA-based load forecast for February 14 (754,477 Dth) by Xcel's estimated curtailed load for that day (approximately 60,000 Dth, yielding a non-curtailed load forecast of 694,477 Dth), the circumstances and reasoning to which Xcel's witnesses testified nonetheless support a finding that Xcel's total planned supply for February 14 (766,354 Dth)—though high—was not so unreasonably excessive as to warrant a disallowance.

The record contains substantial evidence that, on the morning of February 12, Xcel reasonably expected high demand in the spot market based on forecasted weather and the upcoming holiday weekend. It knew there was a legitimate risk that supply disruptions or delivery failures could affect its ability to maintain reliable service over the long weekend. Additionally, because the NNG pipeline had called a system overrun limitation, Xcel knew it could face relatively high imbalance penalties if its supply fell short of customer usage.

Xcel also knew that it would have limited opportunity to procure additional supply over the holiday weekend, when trading platforms would not be operating, and it knew that planning for a four-day period would magnify the uncertainty and complexity inherent to forecasting weather and load, thus increasing the risk of inaccurate forecasting.

For these reasons, the Commission finds that Xcel's load-forecasting and reserve-margin decisions for February 14 fell within the range of reasonable conduct under the circumstances Xcel knew or should have known on the morning of February 12. The Commission therefore will not disallow recovery of gas costs associated with load forecasting for February 13–16.

2. Load Forecasting for February 17

The Commission respectfully disagrees with the ALJs' finding that Xcel met its burden to prove that its short-term load forecasting and resulting gas costs for February 17 were reasonable. Therefore, the Commission will disallow $4,351,593 in extraordinary gas costs.

As noted above, Xcel did not prove that its TESLA load-forecast results adequately accounted for planned curtailments, including on February 17. Further, Xcel did not persuasively show that its plan to procure total supply exceeding forecasted non-curtailed load by 8.5% (corrected as discussed above) was justified as a reasonable supply reserve margin based on relevant factors.

Xcel contended that its February 17 supply-planning decisions were influenced by forecasted warming trends, the expectation that lingering market-volatility fears would cause prices to start high but then fall, and the fact that it needed to purchase spot gas only for the next day. The Commission is not persuaded that these circumstances reasonably support the day-ahead supply-planning decisions Xcel made for February 17.

Xcel's planning data shows that, for February 17, the utility planned to secure total supplies that would exceed its TESLA load-forecast result by 1.8%, the same reserve margin it had planned for February 14 four days earlier.[22]

In light of the disparate circumstances discussed above—which convincingly supported Xcel's February 12 decision to plan a for strong supply reserve margin for the highest-load day of the four-day holiday weekend—the decision Xcel made at the end of the four-day period to pursue the same reserve margin for February 17 requires further explanation. Xcel did not meet its burden to demonstrate the prudence of this decision.

In particular, unlike on February 12, on February 16 Xcel had to plan supply for only the next day. This shorter forecasting window reduced the likelihood of error, thereby reducing the likely benefit of a higher reserve margin. Additionally, unlike the extreme weather forecasts leading into the four-day period, warming trends were expected over the next several days beginning on February 17, ameliorating prior reliability concerns relating to possible supply disruptions.

The imprudence of Xcel's unsupported load-forecasting and reserve-margin decisions is exacerbated by the pricing and market conditions the utility was aware of when planning spot-market purchases for February 17. By the morning of February 16, market conditions had changed dramatically since February 12. Spot-market prices had surged to historic levels and, in just a few days, Xcel had incurred unprecedented levels of gas costs that it planned to pass on to customers. At that time, the knowledge of unprecedented gas prices and the severe financial impacts to customers demanded more careful scrutiny of the reserve margin and supply-planning methods Xcel typically followed under ordinary conditions.

Despite the overwhelming evidence of the extreme pricing environment, however, Xcel failed to meaningfully consider the possibility of mitigating customer financial impacts when selecting a reserve margin for its day-ahead supply-planning decisions for February 17.

Xcel's decision to maintain a relatively high supply reserve margin—8.5% above the forecasted non-curtailed load—for February 17 appears to have been motivated by reliability concerns, with apparently no consideration for cost impacts to customers. But Xcel has not demonstrated that the reliability risks it 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.

Of the various disallowance calculations proposed for Xcel's imprudent load forecasting and reserve-margin decisions for February 17, the Commission finds the Department's $4.35 million recommendation is the most strongly supported in the record. King persuasively testified that reducing Xcel's TESLA load forecast commensurate with planned curtailed load and applying a 2% reserve margin would have yielded a reasonable quantity of planned supply for February 17.

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[22] As discussed above, Xcel's understanding that it planned for 1.8% reserve margins was based on its erroneous TESLA results that did not account for planned curtailment. After correcting for curtailment, total planned supply exceeded the forecasted non-curtailed load by approximately 10.3% for February 14 and by 8.5% for February 17. However, when reviewing the prudence of Xcel's consideration of various factors to select reserve margins, Xcel's contemporaneous understanding that its planned supply would exceed forecasted load by 1.8% on both days is relevant to the question of whether Xcel's reserve-margin decisions were reasonable and made in good faith based on the utility's knowledge at the time.

The Commission will therefore disallow recovery of $4,351,593, representing gas costs Xcel would have avoided by using prudent load-forecasting methods and a reasonable reserve margin when planning its spot-market purchases for February 17.

3. Additional Disallowance Related to Early Release of Curtailed Customers

The Commission will not disallow the additional $2.82 million associated with gas purchased for the portion of interruptible customers that Xcel released from curtailment on February 17.

The Commission agrees with the Department that it was prudent for Xcel to plan to curtail its interruptible customers throughout the February Event, and the fact that Xcel procured so much extra gas supply on February 17 that it decided to end its curtailment order early supports the conclusion that Xcel unreasonably over-procured gas for February 17.

However, the Commission is not persuaded that this additional evidence of over-forecasting warrants an additional disallowance on top of the Department's other proposed disallowance, discussed above, which also stems from the procurement of excessive gas supply based on unreasonable load forecasting for February 17. The Department premised that proposed disallowance in part on Xcel's failure to adequately account for curtailment in its load forecasting. The Department has not demonstrated that its two disallowance calculations related to February 17 load forecasting arise from discrete imprudent acts or persuasively shown that the $2.82 million proposed disallowance is not duplicative of the $4.35 million discussed above.

VIII. Intra-Weekend Purchases

A. Introduction

Although the natural gas market does not formally operate on weekends and holidays, buyers and sellers are sometimes able to transact private sales on those days. During the February Event, Xcel made two intra-weekend gas purchases, totaling 22,280 Dth, at a total cost of $2,820,990.

First, mid-day on February 13, Xcel purchased 14,000 Dth of gas to serve load on February 14 for a fixed price of $95.00/Dth. This price was below the daily spot-market index prices of $231.67/Dth at Demarc and $154.91/Dth at Ventura for that day.

Second, on February 15, Xcel purchased 8,280 Dth to serve load the same day at a fixed price of $157.00/Dth, which was slightly above the Ventura midpoint but below the Demarc midpoint price for that day.

B. Positions of the Parties

1. The Department

The Department contended that all of Xcel's intra-weekend gas purchases were imprudent and, therefore, recommended that the Commission disallow recovery of their entire $2,820,990 cost.

The Department contended that both intra-weekend purchases were based on unreasonably high load forecasts. On February 14, the day of delivery of its February 13 purchase, Xcel ended up with 766,354 Dth of available supply, 7.9% more than its actual load requirement of 710,041 Dth for that day. And on February 15, the day of the second intra-weekend purchase, Xcel ended up with 727,975 Dth, which was 6.5% over its actual load of 683,675 Dth. The Department argued that the fact that Xcel procured this much more supply than it actually ended up needing, much of it at historically high prices, is itself evidence that Xcel's supply planning, including its intra-weekend purchases, were unreasonable.

The Department further maintained that, by February 15, Xcel's knowledge of its actual February 14 load rendered the decision to purchase additional gas on February 15 even further below the threshold of reasonableness. Considering the fact that Xcel had purchased uniform volumes of spot-market gas for each day of the February 13–16 period, observing an actual load far below procured supply on February 14 (the highest-load day) should have signaled to Xcel that it already had more than enough supply for the remaining lower-load days. With this information, the Department argued, it was unreasonable to purchase more gas on February 15.

In addition to unreasonably high load forecasting, the Department argued that the unavailability of Xcel's peak-shaving plants due to Xcel's imprudence (discussed below) also contributed to the intra-weekend purchases. Xcel acknowledged that it may not have made the intra-weekend purchases had its peaking plants been available to address potential reliability issues. Therefore, the Department argued that Xcel's failure to maintain its peaking plants is another reason to hold Xcel's shareholders, not its ratepayers, responsible for the cost of the intra-weekend purchases.

The OAG supported the Department's proposed disallowance.

2. Xcel

Xcel argued that both intra-weekend purchases were made based on a prudent assessment of the circumstances as Xcel reasonably understood them at the time. Xcel emphasized that, when it made the purchases on February 13 and 15, it was operating in a highly dynamic and uncertain environment. It was aware of supply cuts and freeze-offs interfering with gas production, processing, and delivery, some of which affected Xcel directly. These circumstances created significant demand for any available supply across the market and prompted a concern that supply disruptions may impede the ability to meet customers' needs.

Moreover, Minnesota was experiencing extremely cold temperatures at the time, meaning any failure to maintain continuous gas service could pose grave safety risks to customers.

Under these circumstances, Xcel argued that it was reasonable to make these small intra-weekend purchases to ensure it would be able to maintain continuous, reliable service to customers even if it experienced more significant supply cuts.

Xcel argued that the Department's criticisms relied on the hindsight of knowing customers' actual consumption each day and the extent of supply cuts Xcel would experience. However, the prudence standard demands consideration of only the information the utility reasonably had access to at the time the decision was made. As of February 13 and 15, Xcel could not have known that it would not suffer supply cuts so substantial as to interfere with reliable service, and it could not predict customer load with precision. Therefore, Xcel argued that the Commission should reject the Department's disallowance recommendation.

C. Recommendation of the Administrative Law Judges

The ALJs found Xcel's intra-weekend gas purchases prudent and recommended no disallowance. They agreed with Xcel that, in light of the significant uncertainty concerning pricing and supply as of February 13 and 15, it was reasonable to make these purchases to ensure reliable service amid temperatures that could be life-threatening.

D. Commission Action

The Commission finds that Xcel's intra-weekend gas purchases on February 13 and 15, 2021, were within the range of prudent conduct and do not warrant a disallowance.

The Commission agrees with Xcel that the uncertain pricing and supply circumstances, combined with the severity of potential safety consequences if the utility were unable to maintain service to customers in the extremely cold temperatures, justified Xcel's small intra-weekend gas purchases. Although Xcel ultimately procured supply significantly exceeding actual customer demand on the delivery days of both intra-weekend purchases, Xcel's concerns were not unreasonable in light of the limited information and the uncertainty that existed when the decisions were made.

IX. Storage

A. Introduction

Xcel meets a substantial portion of its winter gas-supply needs through leased storage capacity with three major interstate pipeline/storage companies. The utility uses storage to provide reliable supply during high-demand seasons, for day-to-day load balancing, and for price stabilization. Xcel's primary storage service provider is NNG, which has fields located in Iowa and Kansas that are directly connected to many of Xcel's service areas. In February 2021, Xcel's NNG storage contract allowed a daily maximum withdrawal of 168,603 Dth.

Because the NNG storage is directly tied to Xcel's service areas, Xcel also uses that storage for end-of-day balancing. This means at the end of a given day, the difference between (1) the quantity of gas withdrawn from storage and gas purchased and delivered to the pipeline that day, and (2) the quantity of gas that customers actually consumed that day, is treated as an increase or decrease to Xcel's NNG storage quantities. For example, if Xcel customers consumed less gas than acquired on a given day, the unused gas would be treated as an offset to the storage quantity withdrawn that day. The utility uses this balancing function to avoid the imbalance penalties that pipelines assess for taking more or less than the scheduled volume of gas.

B. Positions of the Parties

1. The Department

The Department recommended a $4,051,652 disallowance for failure to maximize available storage gas on February 17.

The Department contended that, although Xcel nominated its full NNG storage capability for February 17, it did not reduce the volume of gas it purchased on the spot market to reflect the maximum storage withdrawal. Comparing Xcel's combined baseload, daily spot-market, and storage gas availability for February 17 against its load forecast, the Department's expert witness stated that Xcel actually accounted for 21,734 Dth less than its contracted maximum storage withdrawal when it was purchasing gas in the spot market for February 17. Applying the February 17 Ventura index price to that volume, the Department concluded that Xcel should have avoided $4.05 million in spot-market purchases by prudently planning for maximum storage withdrawals on February 17.

The OAG supported the Department's proposed disallowance.

2. Xcel

Xcel disputed the Department's argument, stating that the utility planned for and nominated maximum storage withdrawals and reduced its spot-market gas purchases accordingly for each day of the February Event.

Xcel contended that the below-maximum withdrawal the Department referenced represented the utility's *actual* storage usage, not its *planned* withdrawal. Xcel argued that the amount of storage gas it planned to use when making spot-market purchases is the only amount relevant to this inquiry; the next day's actual usage cannot retroactively affect day-ahead spot-market purchases.

Xcel stated that, although it planned for and nominated the maximum storage volume and reduced its spot-market purchases accordingly, by the end of February 17, it had more gas supply available than its customers ultimately consumed. Xcel returned the unused supply to its NNG storage account to balance the flowing supplies with demand. Xcel contended that it was prudent to use its storage account for end-of-day balancing to avoid the substantial pipeline imbalance penalties that otherwise would have been assessed for taking less gas than scheduled.

C. Recommendation of the Administrative Law Judges

The ALJs found that Xcel prudently reduced the volume of gas it purchased on the spot market based on its plan to withdraw the maximum allowable amount from storage on February 17. Although Xcel's customers ultimately used less storage gas than planned, the ALJs found that this did not mean Xcel acted imprudently in its gas-purchasing decisions.

D. Commission Action

The Commission concurs with the ALJs and will not disallow costs associated with the volume of storage gas used on February 17. Xcel persuasively showed that it prudently planned to withdraw the contracted maximum volume of storage gas on February 17 and reduced its spot-market gas purchases accordingly. Although its customers did not ultimately consume as much storage gas as the utility had planned for, that outcome did not cause Xcel to incur any additional gas costs due to the day-ahead nature of spot-gas purchasing. Therefore, no disallowance is warranted.

X. Peak-Shaving Plants

A. Introduction

Xcel owns three peak-shaving facilities: the Wescott liquefied natural gas (LNG) plant, the Sibley liquid propane gas plant, and the Maplewood liquid propane gas plant. These peaking plants store LNG or liquid propane gas that can be dispatched into Xcel's natural gas distribution system to help meet firm customer demand when circumstances require. Xcel uses peaking plants on a limited basis, primarily to supplement pipeline capacity when the system approaches design-day[23] conditions or to maintain reliability when there is an unanticipated supply shortage and no other supply is immediately available.

The Wescott LNG plant, which was built in the 1970s, has two storage vessels capable of storing approximately 2,145,000 Dth of LNG. Wescott's maximum withdrawal capacity is 156,000 Dth on a single day. The Wescott plant is used sparingly; Xcel dispatched it on a total of 146 days in the 10 years preceding the February Event, and only 8 of those occasions involved withdrawing more than 50% of the plant's single-day maximum quantity of LNG.

Xcel also owns two propane-air plants, both built in the 1950s, which can be dispatched to inject propane mixed with air into Xcel's distribution system. The Sibley plant can store approximately 114,000 Dth equivalent of propane and has a single-day maximum withdrawal limit of 46,000 Dth equivalent. The Maplewood plant can store approximately 124,000 Dth equivalent of propane, and its single-day maximum withdrawal is equivalent to 44,000 Dth. In the 10 years preceding the February Event, Xcel dispatched the Sibley plant on a total of 49 days, with a maximum dispatch volume of 14,560 Dth, and dispatched the Maplewood plant on 74 days, with a maximum dispatch of 7,401 Dth.

All of Xcel's peaking plants were unavailable during the February Event. Xcel had suspended operations at Wescott after unplanned releases of gas on December 31, 2020, and January 4, 2021. While investigating the cause of the Wescott releases, Xcel also preventatively suspended operations at Sibley and Maplewood to inspect them for any similar issues.

The Department, CUB, and the OAG recommended disallowing gas costs that Xcel could have avoided if it had run its peak-shaving plants during the February Event. Xcel asserted that it could not have safely run the plants because they were prudently taken out of operation for investigation following the unplanned releases at Wescott. However, the Department, CUB, and the OAG contended that the peaking plants' unavailability was also caused by Xcel's imprudence. Accordingly, they argued, any incremental gas costs Xcel should have avoided by dispatching peak-shaving resources during the February Event stem from earlier acts of imprudence on Xcel's part and are therefore unrecoverable.

To determine whether Xcel's actions surrounding the peak-shaving plants warrant any disallowance, the Commission will consider: (1) whether the unavailability of the peaking plants

[23] "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. Xcel's planned design-day conditions are when the average between the high and low daily temperatures across all Xcel's operational areas is -26°F. Xcel has not experienced design-day conditions since 1996.

was caused by imprudence on Xcel's part; (2) if so, whether absent that imprudence (had the plants been available) it would have been imprudent for Xcel not to operate the plants to reduce spot-gas purchases during the February Event; and (3) if it would have been imprudent not to operate the plants, the amount of cost recovery that should be disallowed for the imprudence.

B. Causes of Peaking-Plant Unavailability

1. Introduction

The Wescott LNG plant uses a vaporizing system to convert stored LNG into a vapor form so it can be injected into Xcel's natural gas system. The vaporizing system operates by pumping previously stored LNG into heat exchangers. The heat exchanger relevant to this proceeding is a metal shell containing numerous tubes bathed in a mixture of hot water and ethylene glycol (WEG). As LNG travels through the tubes, heat transfers from the surrounding WEG to the LNG, raising its temperature from -260°F to 60°F, causing the LNG to vaporize into gas. The gas then flows out of the heat exchanger into Xcel's distribution system for customer use.

Three types of valves were involved in the Wescott processes that led to the unexpected gas releases that prompted Xcel to suspend operation of the peaking plants. First, the flow of WEG into the heat exchanger is controlled by a valve that modulates position to control the heat exchanger's internal temperature (the WEG-supply valve). Second, another valve controls the flow of LNG out of the heat exchanger after it has been vaporized (the temperature control valve). To protect downstream piping from thermal shock, this temperature control valve will close if the now-vaporized LNG's temperature drops too low. Finally, the heat-exchanger system has pressure-relief valves that ensure the pressure within the pipe does not exceed design limits.

Both unplanned releases occurred while Xcel was testing Wescott's full vaporization process, which is the final step in the months-long process of turning the plant over from liquefaction—the process of injecting natural gas into the plant in the summer and liquefying it for storage—to vaporization in preparation for the heating season. Xcel stated that this vaporization-system testing cannot begin until liquefaction has been completed (in 2020, the last day of liquefaction was September 20), after which Xcel needs six to eight weeks to shut down the liquefaction equipment and to perform maintenance, calibrations, and troubleshooting repairs on the vaporization side.

The Sibley and Maplewood peaking plants are different than Wescott because they use propane instead of LNG. They do not have a liquefaction process, but they do use flammable liquids which become flammable gases upon vaporization.

2. Positions of the Parties

a. Xcel

According to Xcel's investigation, the unplanned releases from the Wescott plant were caused by one LNG pump's failure to stop pumping when LNG flow to the vaporizer had stopped. The pump should have stopped when a temperature control valve on the piping downstream of the vaporizer closed due to the low temperature of the LNG coming out of the vaporizer. The temperature of the LNG was low because insufficient WEG was flowing into the vaporization system. The LNG pump continued to push LNG into the chamber, but the chamber was already full because no LNG was able to leave after the temperature control valve had closed. This increased pressure in the chamber, causing the pressure relief valves to open and release gas into the atmosphere.

After the releases, Xcel prepared a root-cause analysis, commissioned a Hazard and Operability Analysis (HAZOP) and a Layer of Protection Analysis (LOPA)[24] for Wescott, and completed a Gap Analysis for all three peaking plants. It also sent the WEG-supply valve for outside testing, which concluded that the valve was not operating properly in response to signals from the plant's operating system because the valve's coating had deteriorated. Specifically, the WEG-supply valve was not moving to all the appropriate setpoints in response to system signals.

Xcel stated that the WEG-supply valve involved in the releases had been installed over 20 years earlier and had operated successfully without any similar events throughout that time. Xcel contended that it could not have determined that the valve was malfunctioning during normal operation or testing because, while the system was operating, the valve's position was obscured due to its location inside the WEG system.

Xcel stated that, prior to the unplanned releases, it had prudently calibrated and tested the system components and had regularly performed planned vaporization testing when liquefaction concluded for the year and the plant was turned over to vaporization. It had also performed additional testing in advance of forecasted cold weather and performed annual liquefaction testing after the heating season ended. Xcel also stated that it had made significant capital improvements and maintenance investments in the Wescott plant, including replacing the liquefaction compressor in 2013 and replacing a series of heat exchangers in 2020.

Xcel stated that it reported the releases to the Minnesota Office of Pipeline Safety (MNOPS) and worked with MNOPS to determine how to bring Wescott back into service safely—which it ultimately achieved in December of 2021. Given the thorough investigation and other steps taken to ensure safe restoration of service after the releases, Xcel argued that it could not have prudently returned the plants to service before the February Event.

Additionally, Xcel argued that it was prudent to take the Sibley and Maplewood propane plants out of service while it investigated the nature of the incident at the Wescott LNG plant, even though the plants use different systems, to minimize the possibility of a reoccurrence. Because Xcel's studies at the propane plants were not completed until June 2021 and the resulting reports were not finalized until September 2021, Xcel argued that it could not have resumed operations at these plants before the February Event.

b. The Department

The Department attributed the unavailability of the Wescott plant to three imprudent acts or omissions by Xcel: (1) Failing to prudently inspect the Wescott WEG-supply valve and ensure it was functioning properly as a part of routine maintenance, which should have prevented the

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[24] A HAZOP study is a system analysis in which various plant processes are reviewed to determine how unsafe or unexpected operating conditions can result from deviations from intended process operation and lead to a public safety risk. A LOPA study assesses how layers of protection can be implemented to prevent unsafe plant operations in the event of unintended conditions.

release incidents; (2) on December 31 and January 4, restarting the Wescott system too quickly after an initial attempt to run the plant failed rather than investigating the cause of the initial failure according to protocol; and (3) failing to timely complete initial investigations after the releases and return the plants to service before the February Event.

i. Failing to Inspect and Maintain the Supply Valve

According to the Department, Xcel failed to take minimally reasonable steps to verify that the WEG-supply valve was functioning as intended as a part of routine maintenance, which would have avoided the unexpected gas releases if done prudently.

The Wescott plant was originally put into service in 1975, and the faulty WEG-supply valve was at least 20 years old at the time of the releases. According to the Department, Xcel did not demonstrate that it had ever verified the valve's functionality or performed maintenance on it prior to the unplanned releases, despite the valve's age and critical role in vaporizer operations. Based on Xcel's records, the utility had checked whether Wescott's operating system was sending the correct levels of current which were intended to trigger the valve's fully open and fully closed positions, but it had never verified whether the valve was actually responding to the operating system by moving to the correct setpoints in response to varying levels of current. The Department contended that prudent utility practice required Xcel to verify that the WEG-supply valve was opening to the correct setpoints as a part of its annual heating-season preparations.

In addition to annual checks, the Department maintained that prudent utility practice required Xcel to periodically test the valve's actual performance before the plant showed outward signs of malfunction. The Department stated that both its own expert and an Xcel consultant had made the same recommendation. The Department's expert, Richard Polich, specifically testified that Xcel's failure to perform any preventative maintenance or testing on a 20-year-old valve to ensure its proper operation was not prudent based on his professional experience.

Contrary to Xcel's claim that it was impossible to verify the physical position of the WEG-supply valve, the Department cited a report by Excel Engineering, a consultant Xcel hired to help investigate the release on December 31, suggesting that field verification of the valve's position was possible. The Department stated that the valve had a visual position indicator that would have allowed plant operators to determine its actual position without draining and disassembling it. Further, the valve had an LCD display screen that displayed the setpoint and position as a percentage, which plant operators should have checked.

The Department contended that, through prudent maintenance and verification, Xcel should have discovered the issue with the WEG-supply valve before any gas releases occurred, replaced the faulty valve, and brought the peaking plants back online before the February Event.

ii. Restarting the System Too Quickly After Initial Failures

The Department further argued that, on the days of the releases, Xcel failed to follow its own operating procedures and industry standards after initial attempts to run Wescott's vaporizing system failed. The Department's expert testified that prudent operation required a thorough investigation and assessment of the reason for any unusual event that leads to major components tripping offline, such as the failed initial attempts to start the Wescott system on December 31 and January 4. Contrary to these procedures, however, after initial attempts to run the plant failed, Xcel tried to quickly restart the vaporizer. Xcel documented that it attempted to restart the system just 52 seconds after the initial failure on January 4. It did not document how much time elapsed between the initial failure and the restart attempt on December 31, but Polich determined it must have been within several minutes.

According to the Department, restarting the system this quickly after the initial LNG-pump trips meant Xcel could not have had sufficient time to investigate the cause of the initial failures between attempts. This also left insufficient time for the requisite cooldown period between LNG-pump trips. Because the LNG pump could not completely cool down before Xcel attempted to run the system a second time, the pump was unable to trip off as designed when the vaporized LNG's temperature again dropped (due to the failing WEG-supply valve) and the temperature-control valve closed to protect downstream piping from too-cold gas exiting the vaporizer. Because the LNG pump was not able to trip off due to the insufficient cooldown period, the pump continued trying to push additional LNG into a piping system that was already full. This caused the pressure in the pipe to exceed the limit, triggering the pressure-relief valves to open, releasing plumes of natural gas into the air.

Polich testified that his conclusion is consistent with Xcel's own understanding of the issue based on the testimony of Xcel witness Steven Martz, which described a timing feature in the control logic that controls certain setpoints for fixed time periods during startup. It is also consistent with a statement in the Excel Engineering report that the second run prematurely ended after a certain period which was not enough time for the cooldown to complete. Polich concluded that this timing issue—caused by Xcel's attempt to restart the system too quickly—was the reason why the LNG pump did not trip. The failure of the LNG pump to function as intended, in conjunction with the malfunctioning WEG-supply valve, caused the unexpected gas releases that led to the peaking plants being taken out of service.

iii. Timeliness of Post-Release Investigations

The Department also argued that Xcel did not demonstrate that its decision to take the Maplewood and Sibley propane facilities out of service for the entire 2020–2021 heating season was prudent. Although it was reasonable to take these plants offline immediately following the Wescott releases, the Department maintained that Xcel should have worked expeditiously to determine the basic cause of the releases while concurrently reviewing its Maplewood and Sibley operations.

The Department's expert testified that Xcel should have identified the basic cause of the releases shortly after they occurred by comparing operating data from past successful start-ups to data from the failed start-ups, which would have shown an unexpected temperature drop in the heat exchanger. Polich testified that there are only three possible causes for a temperature drop in the heat exchanger: (1) too much LNG flowing into the exchanger, (2) WEG supply entering the exchanger at too low a temperature, or (3) not enough WEG flowing into the exchanger. After isolating these narrow possibilities, Polich argued, Xcel could have begun targeted testing at Maplewood and Sibley to determine whether equipment at those facilities had the same problem and, after determining they did not, brought those plants back into service.

To support its contention that Xcel knew or should have known the WEG-supply valve was central to the problem as early as December 31, the Department cited a report prepared by Excel Engineering that identified a conversation with Wescott personnel on December 31 discussing the operation of the WEG-supply valve. The report stated that Xcel had noticed the WEG-supply valves were at an unexpected value and asked the consultant what the value should be on that date. Xcel's root-cause-analysis report and the Excel Engineering report suggest that Xcel attempted to repair the control logic for the WEG-supply valve between December 31 and January 4. Thus, even if Xcel did not know whether the problem related to programming or to the physical valve, it had isolated the issue to the valve by December 31 and, with that information, should have been able to restore the plant to service before mid-February.

Accordingly, the Department concluded that it should not have taken Xcel as long as it did—approximately three months—to complete its root cause analysis of the Wescott releases.

The Department stated that these initial assessments could have been supplemented by further review and refinement over a period of weeks, which would have given Xcel time to bring the plants back online before the February Event.

In response to Xcel's argument that the HAZOP and LOPA studies it conducted after the releases could not have been completed in such a short timeframe, the Department asserted that prudence required Xcel to conduct those types of broader studies periodically as a preventative measure to ensure that its operation and management procedures were being implemented correctly and to assess whether any changes were needed to prevent operational issues. The Department contended that it was imprudent for Xcel to wait until after system failures to perform those tests at its aging peaking plants. If Xcel had prudently conducted those studies, there would have been no need for this additional delay after the unexpected releases.

c. CUB

CUB agreed with the Department that Xcel did not meet its burden to demonstrate that it prudently maintained the Wescott LNG plant and, therefore, argued that the unavailability of the peaking plants during the February Event was caused by Xcel's imprudence. CUB emphasized that the responsibility to prudently maintain the peaking facilities fell on Xcel, not on ratepayers, and it would therefore be unreasonable to hold ratepayers responsible for additional gas costs incurred as a result of Xcel's failure to maintain the plants.

d. Xcel's Reply

Xcel disputed the Department's argument that it should have quickly determined that the WEG-supply valve was the problem on December 31 or January 4 and immediately repaired the valve to avoid having to shut down the plant for months. Contrary to the Department's suggestion that the issue could have been resolved quickly, Xcel argued that prudence required the utility to take the plants out of operation long enough to thoroughly investigate the reasons for the releases and the possible existence of other issues with the plant. Further, Xcel contended that the Department's argument for a faster investigation does not account for the time it took to complete all the steps MNOPS required before resuming operations at Wescott.

Xcel also disputed the Department's claim that Xcel was aware the WEG-supply valve was not moving to the commanded position by December 31 or January 4, arguing that the Department's expert drew unsupported conclusions from the Excel Engineering report. Xcel argued that there is no way to verify that there was an LCD screen on the particular valve at issue, even though a drawing in the valve order form showed one, because no LCD screen was visible in the photograph of the valve in the destructive-testing report. Xcel also argued that, if there was an LCD screen, it is impossible to know whether it would have been visible to the plant's operators while the vaporization system was being tested.

Additionally, Xcel disputed the Department's argument that the attempts to restart the vaporization process after initial failures on December 31 and January 4 contributed to the releases. Xcel argued that this assertion was based on a misinterpretation of the Excel Engineering report and Xcel's root-cause analysis.

3. Recommendations of the Administrative Law Judges

The ALJs did not make findings on whether the unavailability of the peaking plants was attributable to any imprudent action or inaction by Xcel.

4. Commission Action

The Commission finds insufficient evidence to support Xcel's claims that the unavailability of its peaking plants during the February Event was not attributable to the utility's imprudence.

The Department persuasively demonstrated that prudence required Xcel to take different or additional actions at multiple critical points: (1) in its routine maintenance of the peak-shaving plants, (2) immediately after the initial attempts to run the vaporizer failed on December 31 and January 4, and (3) in its post-release efforts to identify and resolve the problem and restore the plants to service. The Department showed that prudent interventions at any of these opportunities would have avoided the result of having no available peaking plants during the February Event.

Xcel failed to effectively rebut the Department's well-supported arguments and did not meet its burden to prove that its decisions that led to the plants being unavailable during the February Event fell within the range of reasonable conduct under the circumstances.

C. Prudence of Not Dispatching Peaking Plants

1. Introduction

When a utility acts imprudently, costs incurred due to that imprudence should not be borne by ratepayers, even if the cost was necessary to serve customers under the circumstances.[25]

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[25] The Commission has most commonly applied this principle in decisions disallowing the recovery of costs for replacement power or alternative fuel supplies needed to serve customers during plant outages that stem from a utility's unreasonable actions. See, e.g., *In re Review of the July 2018–December 2019 Annual Automatic Adjustments Reports*, Docket No. E-999/AA-20-171, Order Adopting ALJ Report as Modified and Requiring Refund at 5 (Feb. 25, 2022); *In re Review of the 2014-2015 Annual Automatic Adjustment Reports for all Elec. Utils.*, Docket No. E-999/AA-15-611, Order Accepting Reports, Requiring Refund, and Setting Additional Requirements at 4–5 (July 21, 2017).

Authorizing the utility to recover any such costs would unjustly and unreasonably penalize ratepayers for the utility's imprudent actions that resulted in costs that should have been avoided.

Accordingly, because Xcel did not meet its burden to prove that its decisions that led to the peaking plants being unavailable during the February Event fell within the range of prudent conduct, the Commission will turn to the question of whether the peaking plants' unavailability caused Xcel to incur additional gas costs that it should have avoided through prudent actions had its peaking plants been available. Such costs, if any, are not recoverable.

2. Positions of the Parties

a. Xcel

Xcel argued that the unavailability of its peaking plants had no impact on its total February-Event gas costs because Xcel would not have used any peak-shaving resources to reduce the volumes of gas purchased on the spot market even if the plants had been available.

Xcel contended that the only way the availability of peaking plants could have affected total gas costs for customers is if the utility had planned to use the plants as a primary supply resource and reduced its February 12 or 16 spot-gas purchases accordingly. But Xcel contended that using peak-shaving plants in such a manner would be contrary to its established practice and typical practice in the industry.

Xcel contended that peaking plants are intended to be used as a last resort when weather conditions are near design-day, when insufficient supplies are available for purchase, or when unexpected changes cause supply to fall short of demand after purchasing decisions have been made. The utility would never deliberately reduce the volume of its spot-gas purchases based on a plan to use peak-shaving resources for supply, no matter how high prices climb.

On the mornings of February 12 and 16, near-design-day conditions were not present and the utility was able to secure adequate supplies to meet forecasted load, so Xcel's ordinary practice did not support running any peaking plants. Therefore, Xcel argued, had the peak-shaving plants been available, it would have been prudent not to use them during the February Event.

b. CUB

CUB contended that, even if Xcel has no established history of using peaking plants to reduce spot-gas purchases when market prices are elevated, the extreme circumstances leading up to, and persisting throughout, the February Event required Xcel to optimize its resources to protect customers not only from potential service disruptions but also from unreasonably high gas costs.

CUB asserted that by the morning of February 12, spot-market prices for gas had reached a 472% increase over five-year annual average prices at the Demarc hub and a 514% increase at Ventura. The prices had doubled in just one day, and a holiday weekend was approaching with cold weather forecasted to continue across key gas-production areas and Xcel's service territory. Although Xcel could not have been expected to predict the full magnitude of the price spike that would ensue by the morning of February 12, the circumstances existing at that point were strong indicators that prices would continue to rise dramatically over the February 13–16 period.

Further, by February 16, the full extent of the price spike was apparent and—had the peaking plants been available—Xcel's failure to make use of any of its peaking resources to reduce the severity of the cost impacts for customers would have been even more egregiously unreasonable.

CUB's expert reviewed data dating back to 2011 and stated that Xcel typically has abundant peak-shaving resources. Therefore, had the plants not been forced offline due to Xcel's imprudence, Xcel could have responsibly used a portion of those resources to reduce spot-gas purchases during the February Event while reserving more than enough of those resources to address reliability issues during the February Event and for the rest of the season.

To calculate an appropriate disallowance, CUB's expert witness identified several different strategies Xcel could have used and then calculated the volume and cost of spot gas Xcel could have avoided purchasing with each of those peaking-dispatch strategies.

CUB's primary recommendation was to disallow $57,895,657, reflecting gas costs Xcel would have avoided if it had dispatched 50% of its daily LNG capacity and 25% of its propane capacity for the entire February 13–17 event and reduced its daily spot-gas purchases accordingly. This recommendation was based both on Cebulko's analysis and on the opinion of another expert, Ronald Nelson, that this amount reflected the optimal strategy for peaking-plant dispatch.

Alternatively, if prudence required the use of peaking plants only on February 17, then CUB would propose the following possible disallowance amounts, depending on which level of peaking-plant dispatch the Commission found minimally reasonable:

- $20,137,247 (100% of daily LNG capacity, 50% of daily propane capacity)
- $10,068,623 (50% LNG, 25% propane)
- $2,488,873 (50% propane, no LNG)

The OAG agreed that the Commission should preclude Xcel from recovering costs resulting from the imprudent maintenance and operation of peak-shaving facilities and argued that the record contains sufficient evidence to support any of the disallowance amounts CUB proposed.

c. The Department

Like CUB, the Department argued that if Xcel's peak-shaving facilities had been available, prudence would have required the utility to use them to reduce the volume of expensive spot gas it purchased on each day of the February Event.

In response to Xcel's contention that it uses its peaking plants only when there are design-day conditions or supply shortages preventing it from purchasing enough gas, the Department noted that Xcel had withdrawn 55,000 Dth to 82,000 Dth each day from Wescott during the 2017–2018 New Year holiday weekend, when prices at the Ventura hub jumped from $2 to $4/Dth up to approximately $65/Dth. Conditions during that event did not approach design-day temperatures, meaning load should not have come close to meeting the maximum capacity of Xcel's system. Therefore, Xcel must have run its Wescott plant for another reason—likely to reduce costs amid elevated spot-market prices.

Based on its conclusion that Xcel's historical practice provides for the use of peak-shaving plants during price spike events in the absence of design-day conditions or supply shortages, the

Department contended that it would have been prudent and consistent with Xcel's demonstrated capability to use a portion of its peak-shaving resources to reduce spot-gas purchases throughout the February Event, in light of the extreme nature of the circumstances.

The Department echoed CUB's position that Xcel should have determined this was the prudent course of action based on the pricing and forecast data that was available as early as the morning of February 12 and continuing throughout the February Event.

i. Peak-Shaving on February 13–16

For February 13–16, the Department contended that Xcel should have reduced its spot-gas volumes by 79,698 Dth each day and supplied the necessary difference from Wescott LNG.

To determine this proposed Wescott withdrawal volume, King considered the facts that Xcel had to purchase uniform volumes of spot gas for each day of the February 13–16 period on the morning of February 12 and that the utility set its spot-gas purchases for those four days at a volume high enough to meet its forecasted load on the highest-load day, February 14. King then determined that the difference in forecasted loads between the highest-load day and the lowest-load day in the four-day period was 79,698 Dth. He observed that the Wescott plant could have supplied that volume on February 14 had it been available (Wescott's maximum single-day withdrawal is 156,000 Dth). The lower-load days would have required smaller Wescott withdrawals and, thus, would have also been well within the capability of the Wescott plant.

Based on King's analysis, the Department argued that it would have been prudent for Xcel to reduce its spot-gas purchases by 79,698 Dth for each day of the four-day period and make up the differences using LNG from the Wescott peaking plant.

Applying the index price Xcel paid for spot gas at the NNG Ventura hub for those days, King determined that this approach would have avoided $49.38 million in gas costs from February 13–16. The Department recommended a disallowance in this amount for Xcel's failure to prudently maintain its peak-shaving plants and use them to mitigate gas costs over the four-day period.

ii. Peak-Shaving on February 17

For February 17, the Department argued that the unprecedented spot-market prices experienced over the four-day period would have prompted any reasonable utility to reassess its plan of action and focus on opportunities to mitigate severe financial impacts to customers. Even if Xcel had not historically used its peaking plants to reduce spot-gas purchases when prices were high, the unprecedented circumstances and the severe magnitude of financial consequences at stake for customers—which were unambiguously understood by February 16—required the utility to make use of its peak-shaving resources to protect customers from unjust, unreasonable costs on February 17.

King testified that it would have been reasonable for Xcel to use 78,000 Dth of LNG on February 17, equal to 50% of Wescott's single-day maximum, and reduce the volume of spot gas purchased accordingly. To calculate the costs Xcel would have avoided by doing so, King applied the NNG Ventura index price of $188.32/Dth for February 17, leading to a total of $14,688,960 in gas costs that should have been avoided.

The OAG and CUB agreed that the Department's recommended disallowance for February 17 is reasonable and supported by the record, but CUB also reiterated support for its initial recommendations discussed above.

d. Xcel's Reply

In addition to arguing that no disallowance was warranted, Xcel also challenged the proposed disallowance amounts. Xcel argued that CUB's decision to primarily recommend a $57.9 million disallowance—as opposed to the lowest number Cebulko suggested—conflicts with the principle that there is a broad range of reasonable conduct under any set of facts, and only conduct that falls below the minimum threshold of reasonableness warrants a disallowance. The mere fact that the utility could have saved more money through one action does not imply that a different approach was not also a reasonable option.

Xcel also contended that CUB and the Department improperly relied on hindsight to argue that, on the morning of February 12, Xcel should have expected spot gas prices to rise to extreme levels over the four-day period. Xcel argued that although prices were higher than usual leading into February 12, there was no reason to expect the unprecedented price spike and no reason to deviate from established practice and start using peaking plants as a primary supply resource.

For both February 12 and 16, Xcel argued that CUB's and the Department's experts improperly relied on hindsight to retroactively identify ways Xcel could have optimized its resources to achieve particular savings based on actual market prices and load outcomes, rather than limiting their evaluations to the prudence of Xcel's decisions based on the forecast and pricing information that was available when the utility was making the decisions.

Additionally, Xcel disputed King's calculation that withdrawing 50% of the Wescott plant's daily maximum amount on February 17 would have avoided $14.69 million in gas costs. While King derived that number using the NNG Ventura index price of $188.32/Dth for February 17, Xcel argued that the correct price to apply would be the actual average price it paid for gas that day, including both index and fixed-price purchases, which was $115.60/Dth. Applying the latter price to a 79,698 Dth daily volume leads to a disallowance of approximately $9.02 million.[26]

3. Recommendations of the Administrative Law Judges

The ALJs found that, if the peaking plants had been available during the February Event, Xcel would not have planned to run them in a manner that would have reduced the volume of spot gas purchased. They found that a decision not to run the plants would have been consistent with Xcel's historical practices and the typical industry practice of dispatching peak-shaving resources only when the weather approaches design-day conditions or when the utility is unable to procure enough supply from other sources to meet customer demand. The ALJs found that a

[26] The Department maintained its support for its $14.69 million calculation, arguing that it accurately reflects the fact that Xcel's geographic diversity of supply allowed it to take advantage of lower prices at the Emerson and Chicago hubs during the February Event, and that prudence would have required Xcel to prioritize reducing its most expensive index-priced transactions at Ventura before reducing volumes it was able to purchase at lower prices.

decision not to run the peaking plants to reduce spot-gas purchases under the circumstances of the February Event would have been reasonable.

The ALJs therefore found that the unavailability of the peaking plants had no financial impact on ratepayers in connection with the February Event and did not warrant a disallowance.

4. Commission Action

a. Peak-Shaving Dispatch February 13–16

The Commission concurs with the ALJs' finding that a decision on February 12 not to use any peak-shaving resources to reduce the volume of gas purchased on the spot market for February 13–16 would have fallen within the range of reasonable conduct under the circumstances.[27] Therefore, the Commission will not disallow any extraordinary costs because of the unavailability of Xcel's peaking plants on February 13–16.

Although gas prices were already elevated leading into the four-day period, it was reasonable for Xcel not to predict a price spike of such a magnitude as to require Xcel to depart from its established practice and consider relying on its peak-shaving pants to reduce the volumes of gas it needed to purchase on the spot market for February 13–16.

Further, given the inherent uncertainty of forecasting weather and customer demand up to four days in advance, and considering the winter storms expected to cause high demand and potential supply disruptions throughout much of the country, it would have been reasonable on the morning of February 12 to plan to reserve peak-shaving facilities so they would be available to address any unanticipated changes in load or supply that might arise during the four-day period. Circumstances necessitating extraordinary cost-mitigation measures were not yet fully apparent when spot-market purchasing decisions had to be made on February 12.

b. Peak-Shaving Dispatch on February 17

Under the extraordinary circumstances demonstrated in the record, however, the Commission respectfully disagrees with the ALJs' finding that, had the peaking plants been available, it would have been reasonable for Xcel not to use any peak-shaving resources to mitigate gas costs on February 17.

By the morning of February 16, circumstances demanding extraordinary action were known and unequivocal. At that time, had the peaking plants been available, Xcel's failure to reevaluate the suitability of its strategies to meet the extraordinary circumstances would have fallen short of the minimum threshold of prudent conduct.

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[27] The Commission does not adopt Findings ¶ 203 of the ALJ Report to the extent it suggests that the Commission's August 30, 2021 order made a finding that any gas purchase at a price below $20/Dth is categorically reasonable and prudent. The Commission did not so order; it only set $20/Dth as the threshold under which prudent gas costs from the February Event could be recovered through the automatic purchased-gas-adjustment process. Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing, at 20, Ordering Para. 3.

The Department, CUB, and the OAG were persuasive in establishing that a prudent utility under the circumstances with access to the same information and resources as Xcel would have planned to dispatch some peak-shaving resources on February 17 to reduce the volume of spot gas it had to purchase at extremely high market prices.

By the morning of February 16, Xcel had observed historically high prices in the spot market, and there was substantial reason to expect prices would remain exceptionally high for February 17. Some areas had seen supply restrictions over the long weekend due to gas production failures and controlled power outages that affected wellhead operations, processing facilities, and gas pipelines. Temperatures were forecasted to remain unusually cold in the south-central United States on February 17, adding demand pressure to the prices amid supply constraints. The ongoing market volatility further increased the risk that spot-market prices would remain extremely high on February 17.

And unlike on February 12, on February 16 Xcel had to plan for only the next day's supply, meaning the risk of significant differences between the forecasted and actual temperatures and load, and the reliability concerns that may accompany such differences, were smaller.

Under the extraordinary circumstances, had the peaking plants been available, it would have been imprudent for Xcel to adhere to its ordinary practice of holding 100% of its peak-shaving facilities in reserve to address unanticipated reliability issues while putting none of this substantial resource to use to ameliorate some portion of the price spike's financial impact on customers. The record demonstrates that dispatching 50% of Wescott's single-day LNG capability on February 17 would have prudently provided meaningful cost savings for customers while preserving a reasonable level of capacity and flexibility to resolve any potential reliability issues that could have arisen during the February Event, with a prudent quantity of resources remaining for the rest of the season.

Considering Xcel's total planned supply and forecasted load for February 17 (corrected in light of the load-forecasting issues discussed above), and the expected weather trends for the rest of the heating season after that date, Xcel has not demonstrated that running its LNG plant to mitigate the financial impacts of the price spike would have created plausible reliability risks that would reasonably outweigh the known, present economic consequences for customers of failing to make use of any peak-shaving resources under the extraordinary circumstances.

The Commission recognizes the gravity of the utility's obligation to provide safe and reliable service, and it commends Xcel for achieving that objective for Minnesota customers throughout the February Event. But this obligation does not obviate the requirement that all rates charged to customers, including purchased-gas adjustments, must be just and reasonable. The standard of prudence required Xcel to actively manage the various tools at its disposal to keep the costs of service just and reasonable under the circumstances. Xcel has not met its burden to prove that its ordinary practice would have been a reasonable strategy to meet the extraordinary circumstances that existed by February 16, duly accounting for the utility's duty to provide service at rates that are just and reasonable.

c. Disallowance Calculation

Having found that Xcel did not meet its burden to prove that its decisions that led to the peaking plants being unavailable during the February Event fell within the range of prudent conduct, and having found that it would have been imprudent not to use any peak-shaving resources to reduce spot-gas purchases for February 17 if the plants had been available, the Commission will therefore disallow recovery of the costs Xcel should have avoided through prudent maintenance and operation of its peak-shaving facilities. This amount totals $14,688,690, based on a prudent withdrawal of LNG equal to 50% of Wescott's single-day maximum.

Both CUB and the Department presented compelling analyses showing that Xcel could have achieved a range of savings using various levels of peak-shaving dispatch, but the Commission finds the Department's analysis most persuasive.

The Department's testimony demonstrates that a reasonable utility in Xcel's position would have saved at least $14,688,960 million by prudently maintaining its peaking facilities and dispatching half of its single-day LNG capacity on February 17 so it could reduce the volume of gas purchased at extremely high spot-market prices for that day. This strategy represents the minimum threshold of reasonable conduct for a prudent utility under the circumstances.

The Commission finds it reasonable to apply the NNG Ventura index price to the disallowance calculation—as the Department did—rather than Xcel's daily spot average price for that day which includes fixed-price transactions and purchases at hubs that had much lower index prices. Basing the disallowance on the index price at the hub where prices were highest reflects that prudence would have required Xcel to take advantage of the geographic diversity of its supply options to maximize cost savings for customers, prioritizing the reduction of the higher-priced transactions before reducing the volumes it was able to purchase at lower prices.

The Commission will therefore disallow recovery of $14,688,960 of Xcel's extraordinary costs, representing the incremental gas costs Xcel incurred because of imprudent acts and omissions resulting in the utility's failure to use peak-shaving resources prudently on February 17.

XI. Financial Hedging

A. Positions of the Parties

1. The OAG

The OAG recommended substantial disallowances for February Event costs that Xcel should have mitigated through prudent financial hedging practices.

The OAG defined hedging as taking a tactical action with the intent of reducing the risk of losing money. The OAG's expert, Brian Lebens, testified that Xcel could have mitigated much of the financial impact of the price spike by using exchange-traded hedges, customizable over-the-counter products, or hedged swing contracts. 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 estimated that, if Xcel had put similar hedges in place prior to the February Event and those hedges had performed even half or two-thirds as well as the actual examples he reviewed, Xcel could have offset $19.3 million to $25.1 million of its February Event costs.

While the OAG recognized that utilities had limited options to financially hedge once the market became aware of extreme prices, the OAG maintained that the gas utilities should have secured hedging opportunities well in advance of the February Event so that they would have had the tools in place to adequately mitigate impacts of the extreme prices.

2. Xcel

Xcel argued that it prudently uses financial instruments to hedge against monthly price volatility in natural gas commodity prices, focusing on protecting against longer-term trends in rising gas prices rather than short-term spikes in the daily market. Xcel's strategy involves concluding hedging transactions from the months of April through October for the upcoming winter, allowing time to analyze market data regarding production trends, demand trends, and storage inventory levels to inform its hedging decisions.

Xcel argued that its financial hedging activities for the 2020–2021 heating season were prudent and followed the hedging strategy contemplated in a Commission order that granted rule variances allowing Xcel to recover certain financial-instrument costs through its purchased-gas-adjustment clause.[28] Xcel asserted the Commission's variance orders allowing recovery of financial hedging costs through the purchased-gas-adjustment clause constitute Commission approvals of the hedging plans discussed in those dockets. Xcel also noted that it provides details of its financial hedging activities each year in annual-automatic-adjustment filings.

Xcel's expert, Richard Smead, generally asserted that the OAG's arguments about the possibility of offsetting February Event costs through a different financial hedging strategy rely on unwarranted speculation and are unsupported by facts and evidence. Smead testified that the OAG's proposed hedging strategy would have involved highly risky commodity speculation akin to gambling without a reasonable likelihood of economic benefit, which no prudent utility would have engaged in.

Further, Smead testified that there is no factual basis to find that the kinds of hedging instruments the OAG suggested were available to the utilities. He contended that some of the price-protection tools the OAG described do not exist and, if they did exist, would be prohibitively expensive. He also testified that some of the specific examples of financial instruments the OAG referred to would not have benefited Minnesota utilities with respect to the February Event because (1) they were priced at Henry Hub in Louisiana, not the Minnesota market hubs of Ventura Demarc, or Emerson; or (2) they were for futures options contracts executed in February 2021 for settlement and delivery in March 2021, after the February Event.

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[28] In 2002, the Commission granted a two-year variance to Minn. R. 7825.2500 and 7825.2400, subject to reporting requirements, to allow Xcel to recover prudently incurred costs of directly related futures market instruments through its purchased-gas adjustment. *In the Matter of a Petition by Northern States Power Company d/b/a Xcel Energy for Approval of Variance to Allow Recovery of the Costs of Financial Instruments Through the Purchased Gas Adjustment*, Docket No. G-002/M-01-1336, Order (January 23, 2002). The Commission has since granted multiple extensions to that variance, the most recent being in 2020 to last through June 2024. *In the Matter of the Petition of Northern States Power Company for Approval of an Extension of Rule Variances to Recover the Costs of Financial Instruments Through the Purchased Gas Adjustment Clause*, Docket No. G-002/M-19-703, Order (February 12, 2020).

Smead contended that other products described by the OAG simply do not exist or would have been prohibitively expensive if they were available.

Xcel therefore argued that no disallowance is warranted.

3. The OAG's Reply

In response to suggestions that the OAG's suggested approach would have required the utility to establish hedges before it could have anticipated the timing or magnitude of the price spike, the OAG emphasized that the inherent nature of hedging is to protect against potential risks before their precise nature and timing can be known. Thus, the prudence of a particular hedging strategy should not be dismissed merely because the utility would have needed to take the action to hedge against a risk before the risk came to fruition.

The OAG disputed Xcel's characterization of its financial hedging plan as having been approved by the Commission and its suggestion that Xcel could not have undertaken any financial hedging activities that were different from or beyond those contemplated in past filings. Although utilities have sought variances from the purchased-gas-adjustment rules so they can recover some costs of financial hedging instruments through their purchased-gas-adjustment riders (which otherwise are only used for gas costs), utilities are under no obligation to obtain pre-approval of financial hedging activities. If the Commission denied a utility's request to recover financial hedging costs through the purchased-gas-adjustment rider, the utility could still seek to recover those costs through other mechanisms, such as base rates.

The OAG asserted that the Commission's prior decisions relate to the specific mechanism of cost recovery; they neither determine the prudence of the specific hedging activities nor limit the utility's authority to engage in financial hedging.[29] The utility maintains the obligation to develop a purchasing strategy, including hedging, that is prudent and reasonable; it is not the Commission's role to direct the utility's hedging decisions.

In response to Xcel's contention that some of the products the OAG described have not been proven to exist, the OAG asserted that utilities are free to negotiate directly with other parties to design over-the-counter hedging contracts suitable to their needs. Such products usually are not available for public viewing, so utilities are uniquely positioned to identify them, and it is the utility's burden to prove they could not have negotiated such products.

B. Recommendation of the Administrative Law Judges

The ALJs found that the record does not support finding that Xcel should have engaged in the hedging strategies urged by the OAG. The ALJs agreed with Xcel that the OAG's proposed hedging strategy would have required Xcel to engage in highly speculative transactions or obtain products that were unavailable.

[29] *See, e.g., In the Matter of the Petition of Northern States Power Company for Approval of an Extension of Rule Variances to Recover the Costs of Financial Instruments Through the Purchased Gas Adjustment Clause*, Docket No. G-002/M-19-703, Order (February 12, 2020) (limiting recovery through purchased-gas adjustment to "prudently incurred cost of financial instruments").

Additionally, the ALJs found that the OAG's hedging strategies would have required Xcel to take actions long before the February Event occurred, without any knowledge that a price spike of this magnitude would occur. They found this inconsistent with the standard for assessing prudency.

The ALJs also stated that Xcel's hedging practices are subject to review and approval by the Commission. They accepted Xcel's characterization of its hedging plan for the 2020–2021 winter as approved and suggested that the plan imposes limits on the amount of hedging that Xcel can engage in, which Xcel followed leading up to the February Event.[30]

The ALJs therefore recommended no disallowance regarding financial hedging.

C. 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 utilities do not need prior Commission approval to engage in financial hedging, and the Commission does not pre-determine the prudence of 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. The fact that the Commission has approved a filing that contemplates certain hedging activities or has not specifically required a utility to take a different approach is not a sufficient reason to find costs resulting from the utility's strategy prudent, nor does it imply that further or different hedging activities would be impermissible.

However, on this record, the Commission is not persuaded that Xcel's financial hedging decisions were imprudent or caused the utility to incur unreasonable gas costs during the February Event. The Commission concurs that Xcel's financial hedging strategy leading up to the event was within the range of prudent conduct for a similarly situated utility under the circumstances.

The Commission therefore will not order any disallowances related to financial hedging. The Commission anticipates that the exploration of more advanced hedging techniques in the future will continue in proceedings established by this order.

XII. Low-Income Exemption

A. Background

In ordering paragraph 12 of the August 2021 order in these dockets, the Commission granted limited exemptions from the extraordinary-cost surcharge in order to mitigate the impact of the event on the most vulnerable customers. Among others, the exemption applied to residential

[30] ALJ Report at Findings ¶¶ 239, 241.

customers who receive or previously received assistance through the Low-Income Home Energy Assistance Program (LIHEAP) in the program years of 2019–2020, 2020–2021, 2021–2022, or 2022–2023. Utilities were directed to update their lists of exempt customers every six months to include any customers who newly receive LIHEAP assistance throughout the 27-month recovery period authorized in that order.

Subsequently, in connection with a rate case filed in a separate docket, the Commission extended the recovery period for Xcel's extraordinary gas costs for residential customers only from 27 months to 63 months.[31] The Commission granted the same extension for all of CenterPoint's customer classes in a separate docket.[32]

B. Comments

In light of the extension of CenterPoint's extraordinary-cost recovery period to 63 months, the City of Minneapolis (the City)—which receives natural gas service from CenterPoint—recommended extending the low-income exemption from the extraordinary-cost surcharge to CenterPoint customers who become eligible for LIHEAP assistance at any point during the 63-month period, through the 2026–2027 LIHEAP year.

Additionally, for CenterPoint, the City recommended expanding the exemption to include any customers who apply for and are determined to be eligible for LIHEAP assistance during the identified years, not only those who actually receive LIHEAP assistance as the Commission previously required. The City asserted that some low-income customers are eligible for LIHEAP but do not receive assistance because the program runs out of funds for a particular year. The City argued that these customers are just as vulnerable to high utility bills as those who actually receive LIHEAP assistance and it would be inequitable to deny them the protection of this exemption merely because LIHEAP funds were insufficient to help all eligible customers.

The Department, CUB, the OAG, and CenterPoint supported the City's proposed modifications to the surcharge exemption for CenterPoint's low-income customers.

At the Commission meeting, Xcel stated that it would support applying these same modifications to protect its own low-income customers throughout the 63-month residential recovery period.

C. Commission Action

The Commission will modify the low-income exemption from Xcel's extraordinary-cost surcharge to incorporate the modifications discussed above. The Commission continues to find it reasonable and in the public interest to exempt low-income customers from the extraordinary-cost surcharges arising out of the February Event. In light of the fact that the surcharge period is now 63 months for Xcel's residential customers, it is reasonable to extend the previously granted

[31] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy's Petition for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-002/GR-21-678, Order Setting Interim Rates, at 6, Ordering Para. 10 (December 30, 2021).

[32] *In the Matter of the Petition by CenterPoint Energy for Approval of a Rate Stabilization Plan*, Docket No. G-008/M-21-755, Order Denying Rate Stabilization Plan but Extending Amortization Period, at 5, Ordering Para. 2 (December 30, 2021).

exemption to customers who newly become eligible for LIHEAP assistance in any year during the extended recovery period. Further, the Commission finds it reasonable to expand the exemption to Xcel customers who applied for and were found eligible for LIHEAP.

XIII. Compliance Filings and Final True-Up

The Commission will require Xcel 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 its surcharge for the remainder of the 27-month (non-residential) and 63-month (residential) recovery periods. Within 60 days, Xcel 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 Xcel to incorporate any remaining true-up in the first annual automatic adjustment report following the end of the 27-month and 63-month recovery periods.

XIV. 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 Xcel to review its practices relating to gas contracting, purchasing, hedging, storage, peak shaving, 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.

Xcel 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 Xcel to file its plan in Dockets No. G-002/CI-21-610 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. For February 17, 2021, the Commission finds that Northern States Power Company d/b/a Xcel Energy did not meet its burden to prove it acted prudently with respect to its load forecasting and, therefore, disallows recovery of $4,351,593.

3. For February 17 only, the Commission finds that Xcel did not meet its burden to prove it acted prudently with respect to its peaking plants and, therefore, disallows recovery of $14,688,960.

4. Within 60 days, Xcel shall make a compliance filing that updates the remaining recovery amount, updates the recovery factors for the remainder of the 27-month and 63-month recovery periods, and updates the tariff accordingly. The Commission delegates approval of this filing to its Executive Secretary.

5. Xcel shall incorporate any remaining true-up into its next annual automatic adjustment report following the 27-month and 63-month recovery periods.

6. With respect to Xcel, the Commission modifies ordering paragraph 12 of its August 30, 2021 order in Docket No. G-999/CI-21-135, as follows:

> ~~The Gas Utilities~~ Xcel must exempt low-income residential customers who ~~receive or previously received~~ applied and were eligible for Low Income Home Energy Assistance Program (LIHEAP) assistance during 2019–2020, 2020–2021, 2021–2022, ~~or~~ 2022–2023, 2023–2024, 2024–2025, 2025–2026, or 2026–2027 as well as those residential customers who are 60 to 120 days in arrears on their natural gas bills, from the extraordinary cost surcharge established in this order. ~~The Gas Utilities~~ Xcel shall ~~are authorized to~~ recalibrate the customers covered by this exemption once every six months—exempting any customers who newly applied and were eligible for LIHEAP or who fall within the category of being greater than 60 days and less than 120 days in arrears on a going-forward basis and removing customers who are no longer greater than 60 days and less than 120 days in arrears. ~~The Gas Utilities~~ Xcel will set exempted customers

based on arrears and current or previous LIHEAP status as of June 30, 2021. These exemptions will be adjusted effective:

> March 1, 2022, based on arrears and new LIHEAP enrollments as of January 31, 2022;
>
> September 1, 2022, based on arrears and customers who applied and were determined eligible for LIHEAP ~~enrollments~~ as of July 31, 2022; ~~and~~
>
> March 1, 2023, based on arrears and customers who applied and were determined eligible for LIHEAP ~~enrollments~~ as of January 31, 2023~~.~~;
>
> September 1, 2023, based on arrears and customers who applied and were determined eligible for LIHEAP as of July 31, 2023;
>
> March 1, 2024, based on arrears and customers who applied and were determined eligible for LIHEAP as of January 31, 2024;
>
> September 1, 2024, based on arrears and customers who applied and were determined eligible for LIHEAP as of July 31, 2024;
>
> March 1, 2025, based on arrears and customers who applied and were determined eligible for LIHEAP as of January 31, 2025;
>
> September 1, 2025, based on arrears and customers who applied and were determined eligible for LIHEAP as of July 31, 2025;
>
> March 1, 2026, based on arrears and customers who applied and were determined eligible for LIHEAP as of January 31, 2026; and
>
> September 1, 2026, based on arrears and customers who applied and were determined eligible for LIHEAP as of July 31, 2026.

7. Xcel must review its gas contracting, purchasing, hedging, storage, peak-shaving, interruptible, customer communications, and other relevant practices and, by September 15, 2022, file a plan in Docket Nos. G-002/CI-21-610 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 filing: 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 it is not using the statute if it has chosen not to proceed with such a plan. The utility should also explain 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 will hold hearings on these plans on or before December 9, 2022.

8. The Commission rescinds ordering paragraph 26 of the Commission's August 30, 2021 order in Docket Nos. G-999/CI-21-135, G-008/M-21-138, G-004/M-21-235, G-002/CI-21-610 and G-011/CI-21-611, regarding a stakeholder group.

9. 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-002/CI-21-610, G-999/CI-21-135**
Dated this 19th day of October, 2022

/s/ Chrishna Beard

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