

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

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

TABLE OF CONTENTS

In the Matter of a Petition of Northern
States Power Company d/b/a Xcel
Energy to Recover February 2021
Natural Gas Costs

STATEMENT OF THE ISSUES	2
SUMMARY OF RECOMMENDATION	3
FINDINGS OF FACT	3
I. Introduction	3
II. Procedural Background	4
III. Standard of Review.....	7
IV. Overview of U.S. Natural Gas Markets	8
V. Background Regarding Xcel	14
VI. Xcel's Awareness Regarding the February Event and Gas Purchases Related to the February Event	16
A. When Xcel Became Aware of the Possibility of Extreme Temperatures and Price Spikes.....	16
B. Xcel's Gas Planning and Purchasing Related to the February Event.....	20
1. Baseload Gas Purchases for February 2021.....	20
2. Spot Gas Purchases Made on February 12 for February 13-16.....	24

3.	Intra-weekend Spot Gas Purchases.....	33
4.	Spot Gas Purchases Made on February 16 for February 17.....	34
VII.	Additional Disputed Issues.....	37
A.	Maximization and Availability of Peaking	37
1.	Background Regarding Peaking.....	37
2.	Wescott LNG Plant.....	42
3.	Sibley and Maplewood Propane Air Plants.....	46
B.	Hedging.....	48
C.	Maximization of Storage.....	53
VIII.	Undisputed Issues	54
A.	Geographic Diversity of Gas Supply	54
B.	Fixed-Price Contracts.....	56
C.	Conservation Efforts.....	57
D.	Third Party Recovery and Other Mitigation	58
E.	Assigning Costs of the February Event based on Consumption.....	59
	CONCLUSIONS OF LAW	61
	RECOMMENDATION	61
	NOTICE.....	62

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

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

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

Eric F. Swanson, Elizabeth H. Schmiesing, and Kyle R. Kroll, Winthrop & Weinstine, P.A., and Matthew B. Harris and Mara K. Ascheman, Xcel, appeared on behalf of Xcel.

¹ In addition to Xcel, the “Gas Utilities” include CenterPoint Energy (CenterPoint Energy), Minnesota Energy Resources Corporation (MERC), and Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co. (Great Plains).

² Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing at 7 (Aug. 30, 2021) (eDocket No. 20218-177548-03) (Order for Hearing).

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

Joseph Meyer and Peter Scholtz, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General Residential and Small Business Utilities Division (OAG).

Brian Edstrom, Attorney at Law, appeared on behalf of Citizens Utility Board of Minnesota (CUB).

Ryan Barlow, General Counsel, Jorge Alonso, Andrew Larson, James Worlobah, and Robert Manning, Minnesota Public Utilities Commission (Commission), appeared as Commission Staff.

STATEMENT OF THE ISSUES

The Commission's Order for Hearing identified the following issues to be addressed in this proceeding:

- A. Did the individual Gas Utilities act prudently before, during, and after the February Event, and are costs related to the February Event reasonable to recover from ratepayers?
- B. Should the Commission disallow recovery of any costs for each utility?
- C. If there are any disallowances for imprudent or unreasonable action, how should these costs be calculated?
- D. The specific prudence questions raised so far, including but not limited to:
 - i. When and to what extent did Gas Utilities become aware of the potential for extreme weather during the February Event, and did they respond prudently and reasonably?
 - ii. Did the Gas Utilities have enough geographic diversity of gas supply and, if not, what was the potential financial impact?
 - iii. Should the Gas Utilities have had additional fixed-price contracts and, if so, what was the potential financial impact?
 - iv. Did the Gas Utilities maximize use of storage capacity and, if not, what was the potential financial impact?
 - v. Did the Gas Utilities maximize use of peaking capacity and, if not, what was the potential financial impact? Has Xcel's maintenance and operation of its Wescott, Sibley, and Maplewood facilities resulted in financial impact?

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

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

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

E. Is it possible to assign extraordinary costs to customers or customer classes based on their consumption during the February Event and, if so, would it be reasonable to do so?³

SUMMARY OF RECOMMENDATION

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

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

FINDINGS OF FACT

I. Introduction

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

2. Natural gas is not price-regulated; rather it is a commodity, and its price is determined by the marketplace. As a result of the cold weather event in February 2021, natural gas prices in some areas of the United States soared to levels never before previously seen.

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

4. During February 13-17, 2021, which the Commission calls the “February Event,” the Gas Utilities maintained service to their customers, but incurred

³ *Id.* at 7-8.

unprecedented levels of under-recovered costs for the purchase of natural gas in order to do so.

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

II. Procedural Background

6. On August 30, 2021, the Commission issued an Order for Hearing, which, among other things, referred these matters to the Office of Administrative Hearings (OAH) for consolidated contested case proceedings.⁴

7. The Commission identified the parties to the contested case proceeding as CenterPoint Energy, Xcel, MERC, Great Plains, the Department, and OAG.⁵

8. The ALJs held a prehearing conference on September 13, 2021, and issued the First Prehearing Order on September 20, 2021.⁶ The First Prehearing Order established a procedural schedule, procedures for discovery, deadlines for prehearing filings, and procedures for the evidentiary hearing and briefing.⁷

9. The First Prehearing Order established the following schedule:

Event	Date
Utility Direct Testimony	October 22, 2021
Intervenor Direct Testimony	December 22, 2021
Rebuttal Testimony by all Parties	January 21, 2022
Surrebuttal Testimony by all Parties	February 11, 2022
All Parties File and Exchange Prehearing Filings	February 14, 2022
Evidentiary Hearing	February 17-18 and 22-23, 2022
Post-Hearing Briefs by All Parties and Proposed Findings Submitted by Utilities	March 15, 2022
Post-Hearing Reply Briefs and Revised Findings Submitted by All Parties (All	March 25, 2022

⁴ *Id.* at 7.

⁵ See First Prehearing Order at 3 (Sept. 20, 2021) (eDocket No. 20219-178082-01).

⁶ *Id.*

⁷ *Id.*

Parties to Submit Redlines of Proposed Findings)	
ALJ Report Issued	May 24, 2022
Arguments and Exceptions	June 3, 2022 ⁸

10. On October 1, 2021, CUB petitioned to intervene as a party.⁹ The ALJs granted CUB's petition on October 12, 2021.¹⁰

11. On October 8, 2021, SLGI petitioned to intervene in MERC's Docket No. G011/CI-21-611.¹¹ On October 20, 2021, SLGI's Petition to Intervene was granted as to the prudence review in MPUC Docket No. G-011/CI-21-611.¹²

12. On October 11, 2021, Minneapolis submitted a Petition to Intervene in MPUC Docket No. G008/M-21-138, stating that CenterPoint is the exclusive gas provider for Minneapolis and its residents.¹³ On October 20, 2021, Minneapolis's Petition to Intervene was granted as to the prudence review in MPUC Docket No. G008/M-21-138.¹⁴

13. A Protective Order was issued on October 8, 2021, to address the handling of trade secret and nonpublic data.¹⁵ A Protective Order for Highly-Confidential Trade Secret Data was subsequently issued on October 11, 2021, and amended on October 26, 2021.¹⁶

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

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

⁸ *Id.* at 4.

⁹ Petition to Intervene by The Citizens Utility Board of Minnesota (Oct. 1, 2021) (eDocket No. 202110-178489-04).

¹⁰ Order Granting Petition to Intervene by The Citizens Utility Board of Minnesota (Oct. 12, 2021) (eDocket No. 202110-178734-04).

¹¹ Petition to Intervene of Super Large Gas Intervenors (Oct. 8, 2021) (eDocket No. 202110-178613-03).

¹² Order Granting in Part and Denying in Part the Petition to Intervene of the Super Large Gas Intervenors (Oct. 20, 2021) (eDocket No. 202110-178980-01) (SLGI's Petition to Intervene in MPUC Docket No. G-999/CI-21-135 was denied as that docket was not referred to the OAH for inclusion in the contested case proceeding.).

¹³ Petition to Intervene (Oct. 11, 2021) (eDocket No. 202110-178639-01).

¹⁴ Order Granting in Part and Denying in Part the Petition to Intervene of the City of Minneapolis (Oct. 20, 2021) (eDocket No. 202110-178978-03) (To the extent that Minneapolis's filings could be construed as a request to intervene in the remaining three dockets, Minneapolis's Petition to Intervene was denied.).

¹⁵ Protective Order (Oct. 8, 2021) (eDocket No. 202110-178630-03).

¹⁶ Protective Order for Highly-Confidential Trade Secret Data (Oct. 11, 2021) (eDocket No. 202110-178678-03); Amended Highly Confidential Trade Secret Protective Order (Oct. 26, 2021) (eDocket No. 202110-179189-03).

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

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

18. The ALJs held a second prehearing conference via Microsoft Teams on February 3, 2022.¹⁸ They then issued the Second Prehearing Order on February 7, 2022, scheduling the evidentiary hearing to be held via Microsoft Teams on February 17, 18, 22, and 23, 2022, beginning at 9:30 a.m. each day, and requiring prehearing filings.¹⁹

19. On February 4, 2022, the Commission issued a Notice of Virtual Public Hearings, scheduling public hearings for March 3, 2022, at 1:00 p.m. and 6:00 p.m.²⁰ On February 14, 2022, the Commission issued an addition to the February 4, 2022, Notice to inform the public that the Commission will also accept video comments as another method to participate in the virtual hearings.²¹

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

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

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

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

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

25. On March 25, 2022, the parties filed Reply Briefs, redlines of the Proposed Findings of Fact, and CenterPoint Energy, Great Plains, Xcel Energy, and MERC filed responses to public comments.²²

¹⁷ Request for the OAH to Hold Public Hearings (Jan. 27, 2022) (eDocket No. 20221-182049-01).

¹⁸ Notice of Prehearing Conference (Jan. 31, 2022) (eDocket No. 20221-182273-01).

¹⁹ Second Prehearing Order (Feb. 7, 2022) (eDocket No. 20222-182513-01).

²⁰ Notice of Virtual Public Hearings (Feb. 4, 2022) (eDocket No. 20222-182412-01).

²¹ Addition to Notice of Virtual Public Hearings (Feb. 14, 2022) (eDocket No. 20222-182753-04).

²² The Administrative Law Judges requested that the parties use their best efforts to provide redlined findings of fact, in order to clearly highlight specific areas of dispute. The parties did so, but given the short timelines required in this matter and the volume of material to be reviewed, the Department, OAG, and CUB noted that the failure to strike or revise certain facts did not constitute a stipulation or waiver as to that issue. The Administrative Law Judges appreciate the efforts of all of the parties to build the record for the Commission's decision and have reviewed the parties' final submissions and the entire record in light of the reservations asserted by the Department, OAG, and CUB.

III. Standard of Review

26. Every rate made, demanded, or received by any public utility must be just and reasonable.²³

27. This proceeding addresses the reasonableness of the costs incurred by the Gas Utilities, and specific to this Report, whether Xcel acted prudently before, during, and after the February Event, and whether the costs related to the February Event are reasonable to recover from ratepayers.²⁴

28. The term “prudence” means “skill and good judgment in the use of resources,” “caution or circumspection as to danger or risk,”²⁵ and “behavior that is careful and avoids risk.”²⁶

29. The parties to this proceeding generally agree on the parameters for determining prudence. Prudence is defined as reasonable action taken in good faith based on knowledge available at the time of the action or decision.²⁷ Actions taken in good faith are those taken without malicious intent,²⁸ exercising the care that a reasonable person would exercise under the same circumstances at the time the decision was made.²⁹

30. Prudence is not evaluated using the benefit of hindsight. Instead, the Gas Utilities’ actions and decisions must be judged on the basis of whether each action and decision was reasonable at the time, under all the circumstances, and based on the information that was or should have been known.³⁰

²³ Minn. Stat. § 216B.03 (2020).

²⁴ Order for Hearing at 7.

²⁵ *Prudence*, MERRIAM WEBSTER, <https://www.merriam-webster.com/dictionary/prudence>.

²⁶ *Prudence*, CAMBRIDGE DICTIONARY, <https://dictionary.cambridge.org/us/dictionary/english/prudence>.

²⁷ Ex. 506 at 28 (King Direct) (“I define prudence as reasonable action taken in good faith based on the knowledge available at the time”); Ex. 103 at 13 (Honorable Direct) (noting that the prudence standard evaluates “whether the utility acted in good faith and reasonably, based upon the facts that it knew or should have known at the time, without the benefit of hindsight.”); Ex. 819 at 13 (Nelson Surrebuttal) (noting the evaluation of prudence must “focus on whether [t]he utilities exercised due care given what was known and knowable of their actions”).

²⁸ Evidentiary Hearing Tr. Vol. 2C at 25 (King) (“I had thought of it . . . as just meaning without malicious intent.”)

²⁹ Ex. 810 at 21 (Nelson Direct) (“The fact that a better outcome could have been reached in hindsight is not in itself permissible evidence in a prudence review; what matters is whether the utility acted reasonably based on the facts it ‘knew or should have known’ at the time. This is related to the concept of a ‘reasonable utility,’ which is expected to exercise ‘the care that a reasonable person would exercise under the same circumstances at the time the decision was made.’”).

³⁰ Ex. 506 at 28 (King Direct) (Prudence must be assessed “based on the information the Gas Utilities had, or could reasonably have obtained, at the time of their actions and not the benefit of hindsight now available.”); Ex. 105 at 1 (Honorable Summary of Pre-Filed Testimony) (“It is my opinion that the Joint Gas Utilities have an obligation to act in good faith, based on the circumstances and facts known at the time, to obtain the necessary gas supplies to serve their retail customers at reasonable cost given the prevailing market at the time of the purchases. If they did so during the Winter Storm, the Joint Gas Utilities have

31. A determination of prudence must recognize that a utility may take a range of actions or decisions that are prudent.³¹ In many instances, there will not be one singular prudent action or decision but rather, a range of actions that are reasonable and prudent.³²

32. Prudence is applied to decisions.³³ Therefore, a prudence review is focused on an examination of specific decisions and whether the decisions were prudent or imprudent.³⁴

33. The burden to prove that its actions were prudent and that recovery of extraordinary costs is reasonable rests on Xcel.³⁵

34. Utilities do not enjoy a presumption of prudence.³⁶ Doubts as to reasonableness are resolved in favor of the consumer.³⁷

IV. Overview of U.S. Natural Gas Markets

35. The natural gas market differs in important and fundamental ways from the electric power market, reflecting the different structures of the two industries and the different products moving through those markets.³⁸ The electric power industry operates as a single, fully-integrated system, and the market operates in real-time, since electricity travels near the speed of light.³⁹ In contrast, the natural gas industry consists of multiple

acted in a prudent fashion and have incurred costs reasonably necessary to provide service to their customers.”); Ex. 600 at 17 (Lebens Direct) (The Commission “should focus as much as possible on evaluating the decisions that would have been prudent based on the information available at the time when those decisions were made.”); Ex. 104 at 4-5 (Honorable Rebuttal) (“This proceeding involves gas supply costs incurred by the Joint Gas Utilities to serve their customers during a recognized extreme weather event. Cold weather events create challenging and dynamic environments that require quick responses. Such circumstances should be considered as part of the overall prudence evaluation.”).

³¹ Ex. 506 at 28 (King Direct) (“In order for the actions of the Gas Utilities to be deemed prudent, they must fall within a range of reasonable action.”); Ex. 105 at 1 (Honorable Summary of Pre-Filed Testimony) (“Prudence is not evaluated on the basis of hindsight, and prudence determinations recognize that a utility may take a range of actions or decisions that are prudent.”); Ex. 819 at 19 (Nelson Surrebuttal) (agreeing that a range of utility decisions taken in response to a specific circumstance may be prudent).

³² See Evidentiary Hearing Tr. Vol. 2C at 23 (King) (“Q. In order to be deemed prudent, the gas utilities’ actions must fall within a range of reasonable action. Correct? A. Yes. Q. Would you agree that a range of reasonable action includes more than one possible action? A. Yes”); Ex. 104 at 3 (Honorable Rebuttal) (“[T]he standard is clear that a range of reasonable utility management decisions made in response to specific circumstances may qualify as prudent – there is no single ‘right answer.’”).

³³ Ex. 810 at 21 (Nelson Direct) (“The fact that a better outcome could have been reached in hindsight is not ... permissible evidence in a prudence review.”).

³⁴ Ex. 819 at 16-17 (Nelson Surrebuttal) (“[T]he focus of a prudence review is on specific decisions – not a vague ‘totality of the decisions’ in which no specific decision can be identified as unreasonable.”).

³⁵ Minn. Stat. § 216B.16, subd. 4 (2020).

³⁶ *In re a Comm’n Investigation into Xcel Energy’s Monticello Life-Cycle Management/Extender Power Uprate Project*, MPUC Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes at 12 (May 8, 2015).

³⁷ Minn. Stat. § 216B.03; see also Order for Hearing at 3 (“In incurring costs necessary to provide service, utilities are expected to act prudently to protect ratepayers from unreasonable risks.”).

³⁸ Ex. 100 at 3, 15-16 (Smead Direct).

³⁹ *Id.* at 3, 15-16.

entities operating independently.⁴⁰ And while dynamic, the natural gas market is far more static than the electric market, particularly during strained operating conditions such as a winter storm.⁴¹

36. The natural gas industry consists of: (1) producers that drill wells that bring raw natural gas to the surface; (2) midstream gathering and processing entities that carry the raw gas to treatment and processing facilities; (3) transmission pipelines which move dry (processed) gas and gas from storage to distant consuming markets; (4) storage providers which supply underground natural gas storage for system balancing and/or for later consumption; (5) local distribution companies (LDCs) that supply and deliver the natural gas actually consumed by utility customers to those customers; and (6) direct-connect end-users, such as power plants or large industrial users, which take natural gas service directly from the transmission pipelines rather than from an LDC.⁴²

37. In 1993, the Federal Energy Regulatory Commission (FERC) implemented Order No. 636.⁴³ Order No. 636 “unbundled” different aspects of the natural gas industry.⁴⁴ Previously transmission pipelines bought and sold the bulk interstate gas, and thus delivered to their customers a “bundled” product consisting of gas, transmission, and storage; through unbundling, FERC instituted the current structure in which transmission pipelines strictly transport and store gas as contract carriers, while buyers and sellers purchase and sell gas separately, moving it through the transportation and storage services provided by the pipelines.⁴⁵

38. To serve the needs of firm customers, a natural gas LDC must contract with two different types of entities. First, the LDC contracts with transportation pipelines, who transport natural gas to the LDC’s service territory from the locations where it is produced, purchased and stored, under agreements and pursuant to tariffs regulated by FERC.⁴⁶ Natural gas is not produced within Minnesota, so the Gas Utilities rely on interstate pipelines to transport gas produced in other states to Minnesota.⁴⁷ Second, the LDC also contracts with suppliers of physical natural gas.⁴⁸

39. The trading of natural gas as a commodity is unregulated, but the United States natural gas market is subject to extensive reporting, observation, and analysis.⁴⁹ Natural gas prices “are driven by the competitive market forces of supply and demand.”⁵⁰

⁴⁰ *Id.* at 3-4.

⁴¹ *Id.* at 16.

⁴² *Id.* at 3-4; *see also* Ex. 506 at 3-4 (King Direct).

⁴³ Ex. 100 at 4 (Smead Direct).

⁴⁴ *Id.*

⁴⁵ *Id.*; *see also* Ex. 506 at 5 (King Direct).

⁴⁶ Ex. 506 at 6 (King Direct).

⁴⁷ *Id.* at 7.

⁴⁸ *Id.* at 6. Suppliers can either be producers of natural gas or marketers, who aggregate supply for commercial disposition. Ex. 100 at 5 (Smead Direct).

⁴⁹ *Id.* at 7; Ex. 506 at 5-6 (King Direct).

⁵⁰ Ex. 506 at 5 (King Direct).

40. Many factors affect the competitive market pricing of natural gas, including weather forecasts, storage levels and activity, current and projected production levels, demand for liquefied natural gas (LNG) exports, pipeline constraints, pipeline tariff provisions and operational actions, and uncertainty of supply reliability.⁵¹

41. The sale and purchase of natural gas takes place both through one-on-one bilateral negotiated transactions directly between counterparties and through open and transparent trading on organized and regulated exchanges, including the Intercontinental Exchange (ICE).⁵²

42. Physical gas is commonly traded at “market hubs” or “market centers,” collectively referred to as “trading hubs.” There are four trading hubs directly relevant to the Minnesota market: (1) Northern Natural Gas Company (NNG) Field/Market Demarcation (Demarc), which is the Kansas boundary between NNG’s supply-area system and the market system that serves Minnesota; (2) Ventura, Iowa (Ventura), where Northern Border Pipeline Company (Northern Border) and NNG intersect; (3) Emerson, Manitoba (Emerson), where TransCanada Pipeline feeds both Great Lakes Gas Transmission LP and Viking Gas Transmission Company (VGT); and (4) NiGas in the Chicago area (Chicago), where extensive storage connects with the pipelines serving Minnesota.⁵³

43. The physical delivery of gas from a seller to a buyer is typically arranged in one of three ways: (1) the daily physical spot market, where natural gas is bought and sold for delivery the next day (or in the case of a Friday, trades include nominations for flow on Saturday, Sunday, and Monday (and if Monday is a holiday, then Tuesday as well));⁵⁴ (2) the monthly spot market, where gas is sold on monthly contracts for the upcoming month during a period called “bidweek” historically being completed sometime during the last week prior to the first day of the month the gas is intended to flow; and (3) long-term contracts, where gas supply is contracted under seasonal, annual, or multi-year deals.⁵⁵ All of these different types of deals can be based on a fixed price or indexed based on a price reporting agency (PRA)⁵⁶ index.⁵⁷

44. Monthly transactions are for delivery of specified volumes, effective on the first of the month (and thus called FOM) and remain in effect each day of the upcoming

⁵¹ Ex. 100 at 20-23 (Smead Direct).

⁵² *Id.* at 7; see also Ex. 506 at 24 (King Direct).

⁵³ Ex. 100 at 5-6 (Smead Direct); see also Ex. 506 at 6-7 (King Direct).

⁵⁴ Ex. 100 at 11, 14 (Smead Direct).

⁵⁵ *Id.* at 11.

⁵⁶ In the wake of the Enron collapse, natural gas sales, futures transactions, the way these transactions are reported to PRAs, and the PRAs themselves became subject to a high degree of government oversight, through initiatives at FERC (such as FERC’s 2003 Policy Statement on Natural Gas and Electric Price Indices and FERC Order No. 704), the Commodity Futures Trading Commission (CFTC) and through major federal legislation (such as the Energy Policy Act of 2005, which provides broad enforcement power to both FERC and the CFTC), in order to ensure the integrity and reliability of price indices, so that they will be representative of the market. *Id.* at 8-9.

⁵⁷ *Id.* at 12.

month.⁵⁸ These deals typically occur during bidweek, which closes prior to the end of the preceding month. The bidweek FOM index is then published on or about the first business day of the month in which the trades will flow.⁵⁹ For February 2021 FOM deals, trading closed on January 28, 2021.⁶⁰

45. Because the major trading platforms are not open on the weekends or holidays, it is difficult for an LDC to find uncommitted supply during the weekend.⁶¹ The intra-weekend market represents a less liquid bilateral market without the benefits of regular business-day trading.⁶²

46. A subset of physical fixed price transactions (both monthly and daily) are reported on a voluntary basis to PRAs such as S&P Global Platts and Natural Gas Intelligence.⁶³ PRAs use this information to produce price indices, which are used for index deals (i.e., deals that are settled based on a published index price).⁶⁴ Fixed price deals that companies choose to report must be reported to PRAs by 3:00 p.m. central time. The PRAs pull the information into a database to create a weighted average (or some other mathematical midpoint).⁶⁵

47. Index deals are common in the natural gas industry—about 84 percent of the physical daily and monthly transactions in 2020 were done based on an index price.⁶⁶ Index deals are the dominant pricing structure, because these transactions share the risk of a changing market for the duration of the agreement.⁶⁷

48. Producers and marketers in the gas sales marketplace begin each sales day offering only index-based deals.⁶⁸ After some time, depending on market conditions (typically a couple of hours later), producers and marketers will begin offering fixed-price deals and stop offering index-based deals.⁶⁹ Many factors affect the competitive market pricing of natural gas, including: weather forecasts, storage levels and activity, current and projected production levels, demand for liquefied natural gas (LNG) exports, pipeline constraints, pipeline tariff provisions and operational actions, and uncertainty of supply reliability.⁷⁰

49. Once physical natural gas is purchased, it needs to be scheduled to flow on the transportation pipelines. FERC requires transportation pipelines to incorporate

⁵⁸ *Id.* at 14.

⁵⁹ *Id.* at 14-15.

⁶⁰ Evidentiary Hearing Tr. Vol. 2C at 26-27 (King).

⁶¹ Ex. 100 at 18 (Smead Direct).

⁶² Ex. 506 at 24-25 (King Direct).

⁶³ Ex. 100 at 7 (Smead Direct).

⁶⁴ *Id.*; see also Ex. 506 at 75 (King Direct) (“Natural gas price indices are widely relied on to be representative of the price of gas at their respective locations.”).

⁶⁵ Ex. 100 at 14 (Smead Direct).

⁶⁶ *Id.* at 7-8.

⁶⁷ *Id.* at 12.

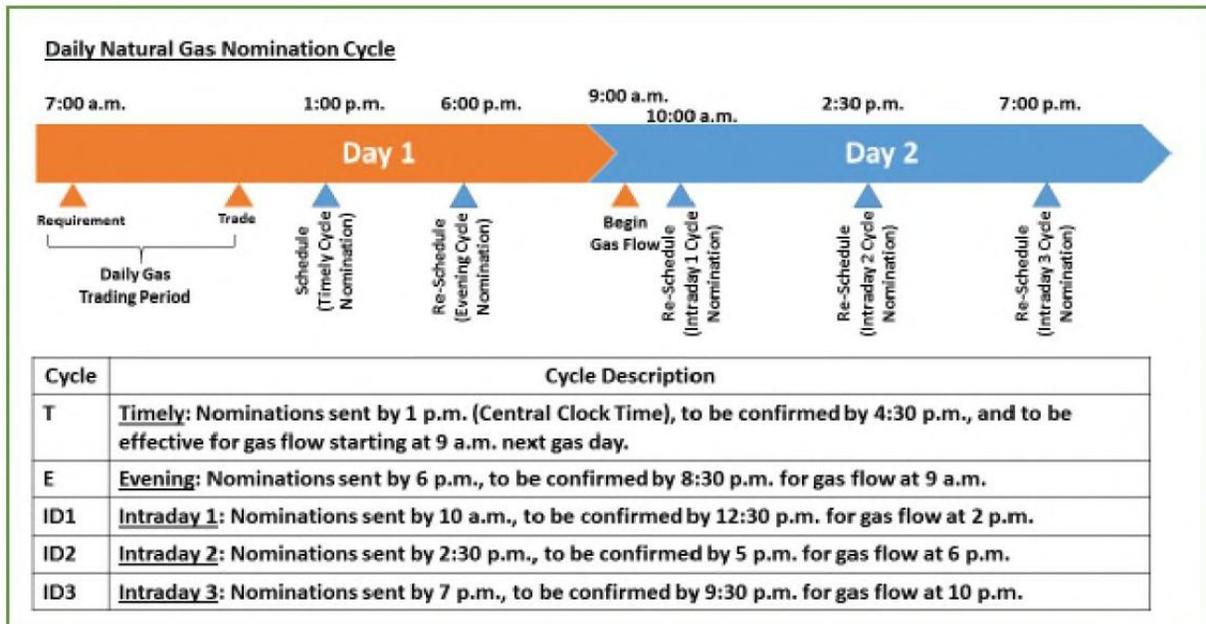
⁶⁸ Ex. 203 at Sch. 2 at 13-14 (Derryberry Direct).

⁶⁹ *Id.*

⁷⁰ Ex. 100 at 20-23 (Smead Direct).

nomination standards developed by the North American Energy Standards Board (NAESB) into their tariffs.⁷¹ These standards set five different cycles upon which natural gas can be nominated — two during the day prior to the Gas Day, which begins at 9:00 a.m. central time, and three opportunities during the Gas Day.⁷² The figure below illustrates these five nomination cycles. This pipeline nomination structure leaves limited ability to respond to changes during the day by buying and selling flowing gas supply.⁷³

NAESB Timeline⁷⁴



50. When a transportation pipeline declares constrained operating conditions, which can include a “critical day,” “system overrun limitation,” or a “system underrun limitation,” LDCs and others flowing gas through pipelines can be exposed to substantial penalties for taking too much natural gas or for being out of balance between receipts and deliveries.⁷⁵ Those penalties can be up to three times the applicable daily spot price per unit on that day.⁷⁶

51. The restriction and penalty provisions of pipeline tariffs mean that during strained operating conditions the penalty rate for a pipeline imbalance is a multiple of the prevailing market price, making an imbalance penalty far more expensive than ensuring an adequate supply at the market price.⁷⁷

⁷¹ *Id.* at 16.

⁷² *Id.* at 16-17.

⁷³ *Id.* at 16.

⁷⁴ Ex. 506 at 24, Figure 10 (King Direct).

⁷⁵ Ex. 100 at 18 (Smead Direct).

⁷⁶ *Id.* at 24.

⁷⁷ *Id.* at 24-25.

52. The physical gas supply options available to the Joint Gas Utilities are: (1) baseload purchases; (2) storage assets; (3) swing supply; and (4) daily spot purchases.⁷⁸

53. Baseload purchases refer to fixed volumes of gas that flow every day for the term of the contract.⁷⁹ Baseload contracts are either monthly or longer-term contracts.⁸⁰ Typically, these baseload purchases are prices at FOM index price or a fixed price.⁸¹

54. There are several different types of storage assets: (1) pipeline storage; (2) virtual marketer storage; and (3) utility-owned storage facilities. Pipeline storage contracts and virtual marketer storage contracts lay out the terms of how these storage assets can be used, including for example, maximum daily withdrawal limits.⁸² Storage supplies are filled during the lower demand summer season for use during the higher demand winter season.⁸³ On a daily basis, storage provides an operational balancing tool to allow utilities to manage uncertainty and variability of load, including across weekends during which gas trading is limited.⁸⁴ Because regional storage around Minnesota is fully subscribed, the Gas Utilities cannot readily acquire additional storage without considerable effort and investment.⁸⁵

55. Swing supply refers to a commitment in advance for a supplier to bring an agreed upon volume of supply at the option or request of the buyer.⁸⁶ Swing supply provides assurance in advance that a quantity of physical gas supply will be available.⁸⁷ Although swing supply provides quantity certainty, those deals are typically priced at a daily spot index.⁸⁸

56. Daily spot purchases refers to gas bought in the spot market for delivery the next day or the next few days (weekend or holiday period).⁸⁹ Daily spot purchases can be purchased for a negotiated fixed price or pricing can be based on the published daily market price index.⁹⁰

⁷⁸ *Id.* at 31.

⁷⁹ Ex. 506 at 21 (King Direct).

⁸⁰ *Id.*

⁸¹ *Id.*

⁸² *Id.*

⁸³ *Id.*

⁸⁴ *Id.*

⁸⁵ *Id.* at 21-22.

⁸⁶ *Id.* at 20.

⁸⁷ *Id.*

⁸⁸ *Id.*

⁸⁹ Ex. 100 at 11, 14 (Smead Direct).

⁹⁰ *Id.* at 12.

V. Background Regarding Xcel

57. Xcel has provided natural gas and electric services to Minnesota customers for over 100 years.⁹¹

58. Xcel operates natural gas facilities in 29 counties in Minnesota, providing retail natural gas service to approximately 470,000 residential, commercial, and industrial customers, as well as to gas-fired electric generation facilities in the State of Minnesota.⁹² Xcel also provides natural gas service in the State of North Dakota.⁹³

59. Company affiliates Northern States Power Company, a Wisconsin Corporation (NSPW) and Public Service Company of Colorado (PSCo) also provide retail natural gas services in Wisconsin, Michigan and Colorado, and Xcel Energy Services (XES) provides the natural gas load forecasting, planning and purchasing expertise and support for the Company and its affiliates.⁹⁴

60. Because Minnesota has no natural gas reserves or production facilities of its own, Xcel must purchase natural gas supplies and arrange for transportation of that natural gas across interstate natural gas pipelines.⁹⁵

61. The natural gas serving Minnesota customers may come from several producing areas, which for Xcel's Minnesota customers are primarily the southwestern and western United States and western Canada.⁹⁶

62. Xcel contracts with approximately 30 different entities for its natural gas supplies.⁹⁷

63. Xcel is regulated by the Commission, which oversees Xcel's natural gas operations by reviewing both Xcel's acquisition of the necessary capacity to provide customers with gas on peak days and its purchases of natural gas supplies for customers.⁹⁸

64. Xcel submits an annual Contract Demand (CD) Entitlements filing through which the Commission reviews and oversees costs associated with the reservation and use of inter- and intra-state pipeline capacity.⁹⁹

65. In the context of a CD Entitlements filing, the Commission also reviews Xcel's "Design Day" conditions planning.¹⁰⁰ Planning for capacity to serve natural gas

⁹¹ Ex. 211 at 8 (Krug Direct).

⁹² *Id.*

⁹³ Ex. 209 at 5 (Johnson Rebuttal).

⁹⁴ See Ex. 200 at 1 (Boughner Direct); Ex. 203 at 1 (Derryberry Direct); Ex. 207 at 1 (Green Direct).

⁹⁵ Ex. 203 at 3 (Derryberry Direct).

⁹⁶ *Id.*

⁹⁷ *Id.* at 5.

⁹⁸ See Ex. 211 at 14 (Krug Direct).

⁹⁹ *Id.*

¹⁰⁰ *Id.*

customers in Minnesota starts by calculating the “Design Day,” which under Minn. R. 7825.2400, subp. 13d (2021), is “a 24-hour-day period of the greatest possible gas requirement to meet firm customers’ needs.”¹⁰¹ 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 degrees Fahrenheit.¹⁰² While the Design Day is an important benchmark for planning purposes, Design Day conditions rarely occur and Xcel has not experienced Design Day conditions since 1996.¹⁰³

66. In the CD Entitlements filing, Xcel updates its Design Day demand and describes in detail the contracts it has with inter- and intra-state pipelines and storage facilities to reserve adequate space on those pipeline systems and in storage facilities, in order to deliver natural gas to Xcel’s customers at Design Day conditions throughout the communities in which Xcel provides natural gas.¹⁰⁴

67. The Commission exercises regular oversight of natural gas supply purchases and Xcel’s recovery of the costs of those supplies through the monthly purchased gas adjustment (PGA) filings and Annual Automatic Adjustment (AAA) of Charges filings.¹⁰⁵

68. Costs associated with purchases of natural gas are first forecast in Xcel’s monthly PGA filings, which are filed on eDockets in a separate docket each month. Xcel reports its actual costs in annual PGA True-up filings, which are filed each year on September 1, after the end of the full natural gas year.¹⁰⁶

69. Concurrent with the PGA True-up filings, Xcel files its AAA, through which it provides significant information on its gas supply policies and actions, and contains comprehensive reporting on various items outlined in Minn. R. 7825.2800-.2840 (2021), including natural gas procurement and dispatching policies, actions taken to minimize costs, hedging analysis, information on Xcel’s variances from Minnesota Rules, as well as actual costs and revenues. Each year in the AAA filing, Xcel also updates its Gas Price Volatility Mitigation Plan.¹⁰⁷

70. In Xcel’s September 1, 2020, AAA filing, Xcel discussed its overall procurement and dispatching policies, explained changes in the gas supply and transportation agreements made for its 2020-2021 gas resource portfolio, and again provided its Gas Price Volatility Mitigation Plan.¹⁰⁸

71. The Commission also reviews Xcel’s use of price hedging to protect customers from high market prices for baseload gas by hedging against monthly natural

¹⁰¹ *Id.* at 14-15.

¹⁰² *Id.* at 15.

¹⁰³ *Id.*

¹⁰⁴ *Id.*

¹⁰⁵ *See id.* at 15-16.

¹⁰⁶ *Id.*

¹⁰⁷ *Id.* at 16.

¹⁰⁸ *Id.*

gas commodity price volatility.¹⁰⁹ The Commission has approved Xcel's hedging plans in a series of dockets dating back to 2001.¹¹⁰ By order of the Commission, Xcel is currently limited to hedging no more than 50 percent of its annual expected winter requirements (through either physical storage or financial hedging), and no more than 25 percent of Xcel's annual expected winter requirements can be hedged with financial instruments.¹¹¹

VI. Xcel's Awareness Regarding the February Event and Gas Purchases Related to the February Event

A. When Xcel Became Aware of the Possibility of Extreme Temperatures and Price Spikes

72. In January 2021, as buyers began contracting for monthly supplies for February, initial National Weather Service (NWS) weather forecasts for February 2021 indicated that temperatures would be warmer than normal, as January 2021 had been.¹¹²

73. During the heating season, Xcel's meteorologists routinely monitor changes in the weather to identify potential severe weather events that could impact Xcel's system.¹¹³

74. By the end of January and the first few days of February, Xcel's internal weather forecast map and the forecast maps of Commodity Weather Group (CWG) and NWS showed Minnesota experiencing colder than normal temperatures over the Presidents' Day weekend, but forecasted normal or above normal temperatures for the southern and south central United States.¹¹⁴ Therefore, in late January, it appeared that, while requirements would be higher in February than expected earlier, Xcel expected abundant supply at reasonable prices would be readily available in the daily market.¹¹⁵

75. The energy industry became aware of the potential for extreme weather at some point in early February,¹¹⁶ but the extent of the extreme weather was not known at that time.¹¹⁷ The weather situation leading to the February Event continued to change and develop.¹¹⁸

76. On Thursday, February 4, 2021, NNG first called a system overrun limitation (SOL) and continued to call SOLs daily through February 17.¹¹⁹ When a SOL is in effect,

¹⁰⁹ *Id.* at 17.

¹¹⁰ See *In re Northern States Power Company Petition 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 (Feb. 12, 2020).

¹¹¹ *Id.*

¹¹² Ex. 100 at 41-42 (Smead Direct).

¹¹³ Ex. 200 at 5-6 (Boughner Direct)

¹¹⁴ Ex. 100 at 41 (Smead Direct); Ex. 200 at 8-9 (Boughner Direct).

¹¹⁵ Ex. 100 at 42 (Smead Direct).

¹¹⁶ Ex. 506 at 51 (King Direct).

¹¹⁷ *Id.* at 53.

¹¹⁸ *Id.*

¹¹⁹ Ex. 801 at 15 (Cebulko Direct).

the Gas Utilities are subject to the risk of significant imbalance penalties by the pipeline if they do not balance gas supply deliveries against actual daily demand.¹²⁰

77. On Friday, February 5, 2021, the weekend before the February Event, Minnesota started to experience colder than normal temperatures.¹²¹

78. Also on February 5, 2021, the National Weather Service's 8- to 10-day outlook forecasted the probability of a cold weather event for the Midwest over the Presidents' Day weekend.¹²²

79. Predictions that the southern United States, including natural gas producing states of Texas and Oklahoma, would be faced with extreme weather did not occur until February 8, 2021.¹²³ On that day, the broader forecasts for the Presidents' Day weekend began to change significantly. As of February 8, 2021, both Xcel's and CWG's forecast showed colder than normal temperatures spreading across the mid-continent, with the extremely cold temperature range expanding even further to the south and west by February 11, 2021.¹²⁴

80. Both the February 8 and February 10 forecasts for Texas, relied on by the Electric Reliability Council of Texas (ERCOT), underestimated the extent of the cold weather experienced during the February Event.¹²⁵ The February 12 forecast was the first Texas weather forecast that captured the extent of the cold weather, and even that forecast had significant errors on certain days.¹²⁶ Notably, the February 12 forecast for Texas projected a shorter duration of cold weather and warmer temperatures than actually occurred.¹²⁷

81. Price spike events that impacted prices for Minnesota utilities had occurred in the past. The price spike event that immediately preceded the February Event occurred over the New Year holiday weekend in 2017-18, and caused Ventura pricing to spike to the then record high level of about \$65/Dth for the three-day delivery period of December 29-31 (2017-18 New Year Event).¹²⁸

82. The 2017-18 New Year Event was similar to the February Event in some ways. First, the event involved extreme cold weather. Second, prices spiked considerably for a short period of time and then returned to pre-spike levels. This price spike at the Ventura hub also occurred over a holiday weekend.¹²⁹

¹²⁰ *Id.*; Ex. 100 at 18 (Smead Direct).

¹²¹ Ex. 801 at 14 (Cebulko Direct).

¹²² *Id.*

¹²³ Ex. 100 at 42 (Smead Direct).

¹²⁴ Ex. 200 at 11-12 (Boughner Direct).

¹²⁵ Ex. 506 at 53 (King Direct).

¹²⁶ *Id.*

¹²⁷ *Id.*

¹²⁸ *Id.* at 15.

¹²⁹ *Id.*

83. But, the 2017-18 New Year Event was not identical to the February Event, as it occurred earlier in the winter and did not involve natural gas production declines as significant as those seen in the February Event. Further, the actual price spike at Ventura, although record setting at the time, was significantly lower than the February Event (~\$65/MMBtu versus \$155/MMBtu at Ventura). Finally, the New Year Event price spike was focused on the Ventura hub.¹³⁰

84. Even with temperatures colder than normal in Minnesota, leading into the February Event, daily spot market gas prices at the supply points for Minnesota remained within a reasonable range, with the daily mid-point of not more than \$3.86/Dth at Demarc and \$4.20/Dth at Ventura through February 9.¹³¹

85. On Wednesday, February 10, daily spot market gas prices began to rise. At the end of the day on February 10, daily prices for deliveries on February 11 settled at \$6.61/Dth at Northern-Demarc and \$6.91/Dth at Northern-Ventura.¹³²

86. Daily index prices at the end of the day on February 11 for gas day February 12 settled at \$15.68/Dth at Demarc and \$15.42/Dth at Ventura.¹³³ While prices increased from the prior day, these prices were within historic ranges for a cold weather event.¹³⁴

87. Over the holiday weekend of Presidents' Day, the Gas Utilities had to purchase gas ratably for a four-day period. This means that the morning of February 12, the Gas Utilities were required to make purchases based upon their forecasted load for the highest usage day of the weekend, and to take the same amount each day.¹³⁵

88. As noted by the Department, "a reasonable actor" would have understood on the morning of February 12, that prices could settle in the range of \$15 to \$65/Dth, meaning a continuing increase of prices from the prior day with a ceiling expectation provided by a recent, similar event. "A reasonable actor would also have understood the potential for prices to manifest outside of that range but would not have ascribed much serious possibility to those outcomes."¹³⁶

89. The Department also has acknowledged that "the price spike that occurred was unprecedented. Also, the index trading that occurred prior to 9 AM occurred, by design, without the benefit of any price discovery."¹³⁷ This means that when Xcel bought gas for the four-day holiday weekend, it did not know prices would spike to the levels they did.¹³⁸ Ultimately, at the end of the day on February 12, daily prices for deliveries

¹³⁰ *Id.* at 11, 17.

¹³¹ Ex. 207 at 12 (Green Direct).

¹³² *Id.*

¹³³ *Id.*

¹³⁴ See Ex. 100 at Sch. 7 (Smead Direct); Ex. 203, Sch. 2 at 24 (Derryberry Direct).

¹³⁵ Ex. 100 at 33 (Smead Direct); Ex. 211 at 25 (Krug Direct); Ex. 506 at 55 (King Direct).

¹³⁶ Ex. 506 at 60 (King Direct).

¹³⁷ *Id.* at 59.

¹³⁸ Ex. 207 at 15 (Green Direct); 211 at 25 (Krug Direct).

February 13 through 16 settled at \$231.67/Dth at Demarc and \$154.91/Dth at Ventura.¹³⁹ Prices had never reached those levels before.¹⁴⁰

90. The temperature in the Twin Cities stayed below zero during the entirety of the four days of February 12 through 15 – the longest stretch of continuous subzero temperatures in nearly 30 years.¹⁴¹

91. Moreover, the cold temperatures experienced in the natural gas producing regions of Oklahoma and Texas led to a massive, unprecedented weather emergency that caused loss of power, loss of heat, and loss of life in those regions. The energy disruptions in Texas and Oklahoma caused significant reductions in available natural gas supply, impacting a huge swath of the country.¹⁴²

92. Between early Friday, February 12, and Monday, February 15, wellhead, processing and pipeline freeze-offs caused a decline of nearly 20 percent in natural gas supply from Texas and Oklahoma.¹⁴³ That decline – combined with loss of wind-turbine efficiency because of blade icing, loss of a unit at the South Texas nuclear plant, generation plant unavailability because of frozen lines and equipment, and frozen coal piles at coal-fired generating stations – resulted in ERCOT declaring an emergency and instituting rolling electric power blackouts.¹⁴⁴ Those blackouts turned off power to the vast bulk of wellhead operations, processing facilities, and pipelines moving gas from the Permian Basin to market.¹⁴⁵

93. As of February 16, the Gas Utilities knew that natural gas production failures had continued to increase considerably.¹⁴⁶ The U.S. Department of Energy's February 16 Situation Update (DOE Update) summarizes the circumstances over the previous weekend, including information the Gas Utilities would have known by that time.¹⁴⁷ Specifically, the DOE Update states that "Extreme cold temperatures have led to sharp increases in natural gas demands to home heating and electricity generation across much of the Central U.S. At the same time, the cold has led to supply disruptions caused by well freeze-offs and natural gas processing plant outages in several producing areas in the U.S. South Central region (TX, OK, KS, LA, AR, MS, AL), which typically accounts for approximately 20-25% of total U.S. gas production."¹⁴⁸ Production outages represented "approximately 7% of total U.S. gas production."¹⁴⁹ The DOE Update also states that

¹³⁹ Ex. 203 at Sch. 2 at 23 (Derryberry Direct).

¹⁴⁰ Ex. 207 at 14 (Green Direct); Ex. 506 at 14 (King Direct) (explaining "the gas prices during the February Event were unprecedented").

¹⁴¹ Ex. 200 at 14 (Boughner Direct).

¹⁴² Ex. 100 at 42, 47 (Smead Direct).

¹⁴³ *Id.* at 48-49.

¹⁴⁴ *Id.* at 49.

¹⁴⁵ *Id.*

¹⁴⁶ Ex. 506 at 62 (King Direct).

¹⁴⁷ *Id.* Although the DOE Update was not released until noon on Tuesday, February 16, it summarizes information that had developed over the long weekend and that a reasonable utility in the gas industry would have been aware of. Ex. 507 at 4 n.3 (King Surrebuttal).

¹⁴⁸ Ex. 506 at Sch. 11 at 7 (King Direct).

¹⁴⁹ *Id.* at Sch. 11 at 2.

“Although production losses due to freeze-offs are temporary, output takes time to return to normal levels, and the cumulative reduction over several days could be substantial.”¹⁵⁰

94. By the time they needed to purchase gas on February 16, the Gas Utilities knew or reasonably should have known that ERCOT, SPP, and MISO were instituting controlled power outages and millions of customers were without power, including wellhead operations, processing facilities, and pipelines moving gas out of the Permian Basin.¹⁵¹

95. During the February Event, the Permian output dropped by 2.9 Bcf/d, or 25 percent, from 1:30 a.m. to 9:00 a.m. Monday, the end of the Sunday gas day. Monday, output fell another 20 percent, and Tuesday, February 16, another 10 percent. At the end of that period, the Permian output had dropped by 8.7 Bcf/d, or 74.5 percent.¹⁵²

B. Xcel’s Gas Planning and Purchasing Related to the February Event

96. Xcel maintained safe, reliable service to its natural gas customers throughout the February Event.¹⁵³ In doing so, however, it incurred extraordinary gas costs in the amount of \$178,978,695.¹⁵⁴

97. The Department and CUB both recommend that a large portion of these costs be disallowed based their arguments as to the prudence of Xcel’s actions. The Department recommends that the Commission disallow recovery of \$122,035,875, if the Commission finds Xcel’s peaking plants should not have been unavailable and should have run during the February Event, and \$37,353,452, without the impact of the peaking plants.¹⁵⁵ CUB recommends that the total disallowance for Xcel’s costs should be \$67,630,122.¹⁵⁶

98. Xcel purchased gas for the February Event in four different time frames: (1) on or before January 28, 2021 (for its February baseload supply purchases); (2) on February 12 (for its daily spot gas purchases to serve customer needs from February 13 through 16); (3) during the weekend of February 13 through 15 (for two purchases made over those days); and (4) on February 16 (for gas supplies to serve customer needs on February 17). These are examined in turn below.

1. Baseload Gas Purchases for February 2021

99. “Baseload” refers to gas a buyer commits to take each day of a month regardless of customer load.¹⁵⁷ Baseload packages are typically purchased at a FOM Index price, prior to the beginning of the season or at the end of the previous month for

¹⁵⁰ *Id.*

¹⁵¹ *Id.* at Sch. 11; Ex. 100 at 49 (Smead Direct).

¹⁵² Ex. 100 at 49 (Smead Direct).

¹⁵³ Ex. 211 at 2 (Krug Direct).

¹⁵⁴ Order for Hearing at 20.

¹⁵⁵ Ex. 507 at 53 (King Surrebuttal).

¹⁵⁶ Ex. 819 at 4 (Nelson Surrebuttal).

¹⁵⁷ Ex. 203 at 6 (Derryberry Direct).

the upcoming month.¹⁵⁸ Baseload purchases represent a common industry supply mechanism up to a certain volume.¹⁵⁹

100. Baseload is a primary physical supply asset that provides monthly price stability.¹⁶⁰ By their structure, baseload purchases offer no flexibility to match daily load with supply and, since the price is generally locked in at the FOM published index price, the buyer may end up paying more or less than the daily spot price depending on how the market moves over the course of the month.¹⁶¹

101. Buying more baseload gas than necessary can lead to operational concerns and issues that, over the long-term, can outweigh any potential benefit of buying additional baseload gas.¹⁶² Purchasers of baseload gas must accept delivery of the daily contract quantity every day, even if baseload purchases exceed actual load.¹⁶³

102. Xcel needed to secure its “baseload” February supplies by January 28, 2021, before the close of trading for February FOM deals.¹⁶⁴

103. The Department contends that Xcel acted imprudently with respect to its baseload gas purchases for February 2021. The Department argues that Xcel used an unreasonably low minimum load forecast, and then failed even to purchase an amount of baseload gas that would satisfy that load figure. As a result, the Department contends that Xcel unreasonably exposed its ratepayers to additional risk and higher prices for gas purchased in connection with the February Event.¹⁶⁵ The Department recommends a disallowance of \$17,040,342, for Xcel’s alleged under-procurement of baseload supply.¹⁶⁶

104. In developing its monthly minimum load forecasts, Xcel Energy considers the most recent five years of actual data for the month in question.¹⁶⁷ Xcel uses five years of data to account for the significant differences that can be seen in winter loads in Minnesota, which are dependent on highly variable weather conditions.¹⁶⁸ For example, in February 2021, Xcel Energy’s five-year look back included data from 2016 through

¹⁵⁸ *Id.* at Sch. 2 at 7 (Derryberry Direct).

¹⁵⁹ Ex. 506 at 21 (King Direct).

¹⁶⁰ *Id.* at 22.

¹⁶¹ Ex. 100 at 14 (Smead Direct); Ex. 506 at 33 (King Direct). Entering February of 2021, over the past three heating seasons daily spot prices had been the same or lower than FOM prices at the Ventura and Demarc market hubs ten and eleven of the prior thirteen months, respectively. Ex. 204 at 9, Sch. 1 (Derryberry Rebuttal).

¹⁶² Ex. 203 at Sch. 2 at 7 (Derryberry Direct).

¹⁶³ *Id.*

¹⁶⁴ Ex. 207 at 11 (Green Direct); Ex. 204 at 6 (Derryberry Rebuttal).

¹⁶⁵ Ex. 506 at 40-41 (King Direct).

¹⁶⁶ *Id.* at 41, Sch. 2 at 1.

¹⁶⁷ Ex. 204 at 7 (Derryberry Rebuttal).

¹⁶⁸ *Id.*

2020.¹⁶⁹ Minimum load was highest in February 2019 and lowest in February 2017; the minimum system needs in February 2019 were nearly double those in 2017.¹⁷⁰

105. The Company's February 2021 minimum load forecast, developed in January 2021, reflected the actual minimum load experienced in those five years, minus third party transports.¹⁷¹ Xcel explained that: "The February 2021 minimum load forecast was 189,763 MMBtu/d [million British Thermal Units per day]."¹⁷² Xcel's minimum five-year historic load for February was 189,753 MMBtu/d—or only 10 MMBtu/d less than the minimum load forecast.¹⁷³

106. The Department contends it was unreasonable for Xcel to use this minimum load figure. The Department opines that using the lowest load day in February in the past five years, without further information, is not a reasonable expectation of the coming month.¹⁷⁴ The Department contends that this load calculation biases the forecast downward. The Department further maintains that, while historical data is an important input to a forecast, it is not reasonable to simply pick the lowest historical number.¹⁷⁵

107. Xcel contends that it does not "focus myopically on a single input when making a baseload purchasing decision," and that Xcel considers weather forecasts, storage balances, and other information in addition to the minimum load number it derives from the five-year lookback.¹⁷⁶

108. It was not unreasonable for Xcel to rely on the minimum load figure it calculated for February 2021, given that Xcel was making a decision as to baseload purchases that would need to be taken in the same amount every day of the month. This is particularly true given that Xcel was making these decisions in January 2021, well before any of the factors leading to the February Event occurred.

109. As to the amount of baseload gas actually purchased, Xcel has stated that its goal is to obtain sufficient baseload gas supply to meet minimum customer demands for the month.¹⁷⁷ The Department's witness, Mr. King, notes that Xcel did not purchase baseload sufficient to satisfy its minimum load forecast for February 2021. For February 2021, Xcel's minimum load forecast was 189,763 Dth/day, but Xcel only procured

¹⁶⁹ *Id.*

¹⁷⁰ *Id.*

¹⁷¹ *Id.*

¹⁷² Ex. 506 at Sch. 7 at 2 (King Direct) (Xcel Response to DOC IR No. 5(g)).

¹⁷³ Ex. 507 at Sch. 2 at 4 (King Surrebuttal) (Xcel Response to DOC IR No. 4(f)).

¹⁷⁴ *Id.* at 29.

¹⁷⁵ *Id.* at 28.

¹⁷⁶ Ex. 204 at 6-7 (Derryberry Rebuttal).

¹⁷⁷ Ex. 203 at 11, Sch. 2 at 7 (Derryberry Direct) (Xcel "purchases enough baseload to serve the minimum expected customer requirements every day for that month, planning to not exceed the demand on warmer days of the month and then providing any needed additional supply through storage and spot purchases as conditions dictate.").

168,600 Dth of baseload supply.¹⁷⁸ That is, Xcel procured 21,163 Dth less than the minimum forecasted daily load.¹⁷⁹

110. However, Mr. King acknowledges that the “optimal level of baseload gas would be dependent on the specific circumstances of each of the Gas Utilities.”¹⁸⁰ Xcel has explained:

While the general goal is to purchase enough baseload to serve the minimum customer needs each day for that month, the Company *must* consider other factors as well in determining a reasonable level of baseload purchases, including recent weather and load forecasts and current gas supply market conditions, among other factors for each period. Importantly, the Company must consider its current storage inventory levels, mandated inventory levels at the end of the heating season and monthly contracted storage inventory requirements. Of necessity, if the preceding month’s storage levels are high, we must decrease planned baseload purchases to make room for using more storage inventory.¹⁸¹

111. Xcel maintains that it considered a variety of factors in making baseload purchase decisions in January 2021, including: (1) the Company’s minimum load forecast for February; (2) market conditions and expectations; (3) load expectations for the entire month; (4) the Company’s storage inventory, storage ratchets and required inventory levels at the end of the month; and (5) the price of those storage inventories compared to the price of available baseload supplies.¹⁸²

112. At the time it made baseload purchasing decisions in January 2021, Xcel had certain information to consider. First, daily spot prices had generally been the same or lower than the FOM baseload price, meaning spot purchases historically provided cost savings for customers, and increasing baseload purchases would have increased costs, if that trend continued.¹⁸³ There were no unusual or problematic market conditions at the end of January indicating a need for more baseload gas,¹⁸⁴ as prices had remained relatively stable for the previous few years.¹⁸⁵

113. Second, as February 2021 approached, the winter had been unusually warm.¹⁸⁶ Longer-term weather forecasts showed colder than normal temperatures were possible for Minnesota by mid-February, but forecasts showed the southern and south central United States to have normal or warmer than normal weather.¹⁸⁷ At the time it

¹⁷⁸ Ex. 506 at 36 (King Direct).

¹⁷⁹ *Id.*

¹⁸⁰ *Id.* at 37.

¹⁸¹ Ex. 204 at 10-11 (Derryberry Rebuttal).

¹⁸² Ex. 203 at Sch. 2 at 17-18 (Derryberry Direct); see also Ex. 204 at 6-15 (Derryberry Rebuttal) (explaining Xcel’s decision in detail).

¹⁸³ Ex. 203, Sch. 2 at 19 (Derryberry Direct); Ex. 204 at 9, Sch. 1 (Derryberry Rebuttal).

¹⁸⁴ Ex. 203, Sch. 2 at 18 (Derryberry Direct).

¹⁸⁵ *Id.*; Ex. 214 at Sch. 2 at 18-19 (Levine Direct).

¹⁸⁶ Ex. 203 at Sch. 2 at 17 (Derryberry Direct).

¹⁸⁷ Ex. 200 at 7-9 (Boughner Direct).

bought baseload gas for February 2021, Xcel had no basis to anticipate the eventual duration or geographic scope of the cold weather to come, or the consequences of that weather on gas prices.¹⁸⁸

114. Third, in January 2021, Xcel had higher than planned storage inventory levels, partially due to a warmer heating season to date.¹⁸⁹ In order to meet its inventory limits on NNG by March 1, and near zero by the end of the season (avoiding substantial penalties), Xcel planned to make significant withdrawals throughout February.¹⁹⁰ Under these circumstances, Xcel intended to use these storage withdrawals as substitute for incremental baseload quantities.¹⁹¹ Further, the storage quantities remaining at the end of January had been acquired prior to the winter at lower prices than those for monthly baseload.¹⁹²

115. The Department's disallowance recommendation relies on a rigid approach to baseload purchasing decisions. According to the Department, Xcel was required to purchase baseload not just to meet its minimum forecasted load, but to meet a greater load figure. Further, because Xcel identified purchasing baseload gas to meet minimum load as a "goal," the Department contends it was required to make purchases in that amount without regard to other factors. The Department's reasoning is inconsistent with the standard for evaluating prudence, which permits utilities to evaluate the information known to them and make reasonable decisions based on that information.

116. Considering the information known to Xcel in late January 2021, its purchase of baseload gas for February 2021 was not imprudent, and no disallowance is warranted related to this decision.

2. Spot Gas Purchases Made on February 12 for February 13-16

117. Leading up to the February Event, Xcel's meteorologists first noted the potential for colder than normal temperatures to occur in Minnesota, and then later noted that the colder forecast covered greater portions of the mid-continent as the President's Day weekend approached.¹⁹³ They issued an Extreme Cold Alert for Minnesota on February 4, 2021, and these alerts continued through February 16, 2021.¹⁹⁴

118. Additionally, NNG called a system overrun limitation (SOL) on February 4, 2021, and continued to call SOLs (called when a pipeline's operating integrity is in question) or Critical Day Notices (called when the operating condition of the pipeline

¹⁸⁸ *Id.* at 13.

¹⁸⁹ Ex. 204 at 11 (Derryberry Rebuttal).

¹⁹⁰ *Id.* ("In order to meet its inventory limits on NNG of no more than 3,100,000 Dth by March 1, and near zero by the end of the season, the Company determined it needed to average withdrawals of 90,500 Dth NNG, 7,600 Dth ANRS, and 15,000 Dth ANRP per day for the month of February.").

¹⁹¹ *Id.*

¹⁹² *Id.*; Ex. 203 at Sch. 2 at 36 (Table 4) (Derryberry Direct) (showing February baseload supplies at an average cost of \$2.74/Dth and storage gas at an average cost of \$1.89/Dth); see also Evidentiary Hearing Tr. Vol. 2C at 42 (King) (confirming it would not be unreasonable to use less expensive storage gas).

¹⁹³ Ex. 200 at 6-7 (Boughner Direct).

¹⁹⁴ *Id.*; Ex. 203 at Sched. 2 at 27 (Derryberry Direct).

system has severely deteriorated, and the integrity of the system is threatened) each day until after the February Event.¹⁹⁵

119. When a SOL is in effect, the Gas Utilities have no tolerance available to be short on balancing gas supply deliveries against actual daily demand without being assessed significant imbalance penalties by the pipeline.¹⁹⁶

120. In response to predictions of extreme cold weather, Xcel instituted multi-disciplinary actions across its operations, including:

- a. Daily coordination meetings with all gas teams, including Operations, Planning, and Engineering;¹⁹⁷
- b. Performing enhanced inspection and maintenance at key stations across its system prior to the cold weather event;¹⁹⁸
- c. Meetings between Operations, Gas Control, and Engineering to align optimum staging locations for employees to position them to quickly react and adjust equipment as needed;¹⁹⁹
- d. Increased staffing for monitoring the gas system and staffed specific regulator stations and control equipment in vulnerable areas;²⁰⁰
- e. Regularly reviewing operating processes and procedures with employees to ensure customer and employee safety was at the core of Xcel's work throughout the event;²⁰¹
- f. Making several Compressed Natural Gas (CNG) mobile units available at locations identified by the planning process described above in the event Xcel encountered an unexpected need for additional pressure on its system, though ultimately, these were not needed.²⁰²

121. Additionally, Xcel determined it needed to curtail its 325 interruptible gas customers, so Customer Relations staff contacted these customers to communicate the interruption details.²⁰³ Xcel determined that curtailing these customers would ensure that

¹⁹⁵ Ex. 801 at 15 (Cebulko Direct); Ex. 214 at Sch. 2 at ¶15 (Levine Direct).

¹⁹⁶ Ex. 801 at 15 (Cebulko Direct); Ex. 214 at Sch. 2 at ¶15 (Levine Direct).

¹⁹⁷ Ex. 211 at 20 (Krug Direct).

¹⁹⁸ *Id.*

¹⁹⁹ *Id.*

²⁰⁰ *Id.*

²⁰¹ *Id.* at 20-21.

²⁰² *Id.* at 21.

²⁰³ *Id.*

it had sufficient capacity to maintain reliable service, and the curtailment reduced the amount of gas Xcel needed to purchase on the spot market.²⁰⁴

122. Curtailments (also referred to as the Company's demand response programs) can provide system relief during high demand days and reduces demand for gas supply on critical days.²⁰⁵

123. Xcel offers natural gas service on an interruptible basis to Commercial and Industrial sales and Transportation customers.²⁰⁶ Customers on interruptible rate services agree to curtail their gas usage within one hour of notification and, in return, they pay a reduced rate per therm on their gas distribution rates year-round.²⁰⁷

124. In order to qualify for this program, customers must provide and maintain suitable and adequate alternate fuel-capable standby facilities and have access to sufficient standby alternate fuel for curtailment periods.²⁰⁸ When gas interruptions are called, the Company relies on customers to curtail system gas use and switch to their alternate fuel source.²⁰⁹ If unauthorized use of gas occurs during a control period, the Xcel's tariff governing interruptible customers imposes penalties, which are then credited to firm customers.²¹⁰

125. Xcel called its first curtailment to run from February 5, 2021, through February 9, 2021.²¹¹

126. By the time colder temperatures arrived in Minnesota on February 5,²¹² Xcel had already made its baseload gas purchases for February 2021, as described above.

127. On the morning of Friday, February 12, 2021, Xcel need to purchase gas for delivery over the four-day Presidents' Day weekend (February 13-16), and initially only index-based deals were offered at the start of trading.²¹³

128. Once fixed price deals became available in the market after 9:00 a.m. Central, reported prices were dramatically higher than the prior days' pricing.²¹⁴ Opening

²⁰⁴ *Id.*; see also Ex. 204 at 15 (Derryberry Rebuttal) ("Once the Company has prepared its load forecast, the Company then needs to determine whether its existing supply (baseload and storage) can serve the load, and whether daily spot purchases and/or interruptible curtailments are necessary. These are decisions the Company necessarily makes shortly before purchasing spot gas, so in this case decisions made on the morning of Friday, February 12; and then again on the morning of Tuesday, February 16.")

²⁰⁵ Ex. 203 at Sch. 2 at 4 (Derryberry Direct).

²⁰⁶ *Id.*

²⁰⁷ *Id.*

²⁰⁸ *Id.*

²⁰⁹ *Id.*

²¹⁰ *Id.* (explaining changes Xcel made to its tariff in response to customer non-compliance with curtailments called during the 2013-14 heating seas and in response to a severe weather event in 2019).

²¹¹ Ex. 211 at 21 (Krug Direct).

²¹² Ex. 200 at 14 (Boughner Direct); Ex. 801 at 14 (Cebulko Direct).

²¹³ Ex. 207 at 12-14 (Green Direct)

²¹⁴ *Id.* at 14.

fixed price deals on February 12 were roughly five times the daily midpoint of natural gas at Demarc and Ventura the day prior, February 11 and continued climbing.²¹⁵

129. At the end of the day on February 12, daily prices for deliveries February 13 through 16 settled at \$231.67/Dth at Demarc and \$154.91/Dth at Ventura.²¹⁶ Prices had never reached those levels before.²¹⁷ Though prices had been rising in the days before February 12, there were no market signals suggesting that prices would surge to this degree.²¹⁸

130. Weekends and holiday weekends are the least flexible and adaptable times in the natural gas market.²¹⁹ Large scale trading does not occur on weekends and holidays. Although buyers can purchase and transport gas intra-weekend, it is a less liquid bilateral market.²²⁰ Therefore, Xcel needed to make spot purchases on Friday, February 12 for the four days of February 13-16, and it was required to take that gas ratably. This means that Xcel had to purchase the same amount of spot gas for February 13, 14, 15, and 16.²²¹

131. In making a spot purchase on February 12, Xcel had to consider multiple factors, including: (1) daily weather and load forecasts; (2) curtailed load from its interruptible customers, reducing the need for daily spot gas; (3) maximizing its storage withdrawals, again reducing the need for daily spot gas; (4) supply-side issues, including overall demand expected and the potential for potential supply interruptions or failures; (5) the impact on customers and communities if reliable service was not maintained; and (6) having an adequate “safety net” of supply to ensure continued service in the face of the uncertainties inherent in an extreme weather event.²²²

132. Xcel begins the purchasing process by developing a load forecast, which relies on weather forecasts developed by Xcel’s meteorologists. The meteorologists generate high and low temperature forecasts by consulting several weather models and subscription energy vendor forecasts for major cities.²²³

133. Xcel uses these weather forecasts as inputs into the TESLA model, which is the system used by Xcel to produce LDC load forecasts.²²⁴ TESLA provides load forecasts to the energy industry worldwide.²²⁵ The model itself is a linear regression-

²¹⁵ *Id.*

²¹⁶ Ex. 203 at Sch. 2 at 23 (Derryberry Direct).

²¹⁷ Ex. 207 at 14 (Green Direct); Ex. 506 at 14 (King Direct) (explaining “the gas prices during the February Event were unprecedented.”).

²¹⁸ Ex. 207 at 14 (Green Direct).

²¹⁹ Ex. 506 at 25-26 (King Direct).

²²⁰ *Id.* at 24–25.

²²¹ *Id.* at 26.

²²² See Ex. 204 at 15-23, 28-30 (Derryberry Rebuttal).

²²³ Ex. 200 at 4 (Boughner Direct).

²²⁴ *Id.* at 4-5.

²²⁵ Ex. 201 at 2 (Boughner Rebuttal).

based load forecasting model and is a “learning model,” that adjusts its forecasts based on recent actual load data to produce a “best-fit” load forecast.²²⁶

134. Over the ten-month period ending in mid-January 2022 (304 observations), the TESLA model averaged a load forecast variance of just 0.65 percent.²²⁷

135. Heading into the 2021 Presidents’ Day weekend, Xcel had called a system-wide curtailment the previous weekend.²²⁸ Because the TESLA model incorporates actual historical data, the reduced load numbers resulting from this curtailment were incorporated into the TESLA model load forecast used by Xcel, reducing the anticipated load.²²⁹ Further, at the time it made purchasing decisions on February 12, 2021, Xcel had called another system-wide curtailment for the coming long weekend, due to the extended cold weather forecast for Minnesota and because of growing concern about distribution constraints.²³⁰ Xcel began its curtailment for all of its non-firm customers on Friday, February 12 at 11:00 a.m. through Thursday, February 18 at 9:00 a.m.²³¹

136. The Department and CUB both contend that Xcel erroneously included interruptible customers in its load forecast calculation, increasing the amount of spot gas it had to purchase in advance of the Presidents’ Day weekend. The Department recommends a disallowance of \$26,875,063, in costs for February 13-16.²³² CUB recommended a disallowance of \$9,734,465 related to Xcel’s load forecasting during the February Event.²³³

137. However, Xcel clarified this issue by providing evidence that the Company does not input planned curtailment numbers into the system, but that the TESLA model relies on recent actual historical experience, including reduced load from curtailments. Xcel witness Michael Boughner testified that:

As a weather forecasting tool, the TESLA model forecasts native load based on the weather. It does not forecast things like interruptible customer responsiveness for calls to curtail, which can be based on many things other than the weather. However, the TESLA model does include a feature that adjust[s] its forecasts based on recent actual data.²³⁴

²²⁶ *Id.* at 3; Ex. 204 at 4 (Derryberry Rebuttal).

²²⁷ Ex. 204 at 21-22 (Derryberry Rebuttal).

²²⁸ Ex. 211 at 21 (Krug Direct).

²²⁹ Ex. 204 at 16-17 (Derryberry Rebuttal).

²³⁰ Ex. 203 at Sch. 2 at 37 (Derryberry Direct).

²³¹ Ex. 211 at 21 (Krug Direct). The Company ultimately released some of its non-firm natural gas customers from the call to curtail at 6:00 p.m. on February 17, the remainder were not released until 9:00 a.m. on February 18. *Id.*

²³² Ex. 506 at 71, 73, Sch. 2 at 3 (King Direct). The Department recommends an additional amount for alleged over-forecasting on February 17, which is discussed below.

²³³ Ex. 811 at 7 (Cebulko Surrebuttal); Ex. 819 at 4 (Nelson Surrebuttal). Note that this figure is for the entire five-day period of the February Event.

²³⁴ Ex. 201 at 3 (Boughner Rebuttal).

138. Xcel witness Richard Derryberry further explained that Xcel does not remove estimated, forward-looking, curtailment volumes from the TESLA system's inputs, but that the system considers reduced actual load figures, and that Xcel also factored in its planned system-wide curtailment in when making the decision about the amount to purchase, independent of the TESLA modeling.²³⁵ As Mr. Derryberry explained, the TESLA forecast is the "starting point for our daily gas planning activities, rather than the final word," and Xcel takes a variety of factors into account when deciding how much gas to purchase.²³⁶ Mr. Derryberry further points out that the forecast compared to actual numbers shows that the curtailment was factored into the calculation; if it had not been, there would have been a greater variance between the forecast and actual load reflecting the load for interruptible customers.²³⁷

139. The record supports finding that Xcel took its most recent curtailment and its planned curtailment information into account when purchasing gas on February 12.

140. Along with these curtailments, Xcel planned to withdraw the maximum allowable amount from storage each day of the February Event and nominated withdrawals at those volumes.²³⁸ Xcel reduced its planned daily gas purchases for the February Event by those maximum withdrawal volumes.²³⁹

141. After those purchases were made and at the end of each day during the pricing event, Xcel had more gas supply available than was ultimately needed.²⁴⁰ Xcel used its storage account to balance flowing supplies and demand and avoid substantial pipeline penalties.²⁴¹

142. As it planned its February 12 daily spot purchases, Xcel knew that based on the current forecasts and the long weekend ahead, there would be significant interest in the daily spot market.²⁴²

143. Xcel was concerned that if it waited until later in the day to make its purchases there might not be adequate supply available at the locations needed to get gas to Xcel's customers.²⁴³

144. Further, Xcel anticipated its ability to make purchases for the long weekend after Friday would be constrained.²⁴⁴

²³⁵ Ex. 204 at 16 (Derryberry Rebuttal).

²³⁶ *Id.* at 4.

²³⁷ *Id.* at 17.

²³⁸ Ex. 203 at Sch. 2 at 32 (Derryberry Direct); Ex. 214 at Sch. 2 at ¶¶62-64 (Levine Direct).

²³⁹ Ex. 203 at Sch. 2 at 32 (Derryberry Direct); Ex. 204 at 30 (Derryberry Rebuttal); Ex. 214 at Sch. 2 at ¶64 (Levine Direct).

²⁴⁰ Ex. 203 at Sch. 2 at 32 (Derryberry Direct).

²⁴¹ *Id.* at Sch. 2 at 33-34.

²⁴² Ex. 207 at 13 (Green Direct).

²⁴³ *Id.*

²⁴⁴ *Id.* at 7.

145. Finally, Xcel determined that natural gas supply disruptions or delivery failures over the course of the long weekend were a legitimate and serious concern, as freeze-offs were already occurring in some parts of the natural gas production areas.²⁴⁵

146. Finally, Xcel was aware of the potential for imbalance penalties. On the largest pipeline, NNG, those penalties would be three times the daily spot price.²⁴⁶

147. Xcel began purchasing gas around 6:40 a.m. on Friday, February 12, and completed its purchases by 9:00 a.m., before any fixed-price deals were offered.²⁴⁷ At that time, there was uncertainty about the direction of pricing for that day, following increases in price the day prior.²⁴⁸

148. Xcel secured sufficient daily spot gas on the morning of February 12 (together with its prior baseload purchases, delivered supply purchases, called curtailment, and planned maximum storage withdrawals) to position Xcel to cover its forecasted load plus a reserve margin.²⁴⁹

149. Xcel's total planned supplies for the four days covered by the February 12 spot purchases, compared to its forecasted load, was as follows:²⁵⁰

	Saturday, Feb. 13th	Sunday, Feb. 14th	Monday, Feb. 15th	Tuesday, Feb. 16 th
Total Planned Supplies	752,940	766,354	727,975	740,523
Forecasted Load	729,191	754,477	724,738	674,779
Percent Planned Supplies Exceeded Forecasted Load	3.3	1.8	0.4	9.7

150. Ultimately, Xcel's average costs of \$150/Dth for its February 12 natural gas purchases, while unprecedented in the United States' natural gas markets, was

²⁴⁵ Ex. 207 18 (Green Direct) ("We were already seeing evidence of the market drying up as we were concluding our purchases using the index-based market. Offers on the ICE platform were getting snapped up in a matter of seconds"); Ex. 215 at 19-22 (Levine Rebuttal) (noting that NNG warned shippers of freeze offs the afternoon of February 11).

²⁴⁶ Ex. 100 at 18, 24 (Smead Direct); Ex. 203 at Sch. 2 at 33, n. 20 (Derryberry Direct) ("NNG's penalties, for example, can be as high as 3 times the applicable spot price for each Dth subject to penalty. For the February event, penalties would amount to \$465 to \$696 Dth/day, which is far more than buying more gas from the market at the daily index prices of \$155 to \$232 Dth/day over President's Day weekend.").

²⁴⁷ Ex. 207 at 13-14 (Green Direct).

²⁴⁸ *Id.* at 14.

²⁴⁹ Ex. 203 at Sch. 2 at 26, 33 (Derryberry Direct) ("A gas supply reserve margin is also critical to ensuring continued service to customers during a cold weather even or other challenging conditions.").

²⁵⁰ See Ex. 203, Sch. 2 at 26, Table 3 (Derryberry Direct).

significantly below the highest reported price of \$400/Dth at the Demarc Hub and was below the midpoint prices reported at Demarc and Ventura.²⁵¹

151. The Department and CUB contend that Xcel's supply reserve margin for its gas purchases was unreasonable. The Department contends that a supply reserve margin of 2 percent is a reasonable figure to use. Mr. King, the Department's witness, acknowledged that it is important to have a reserve margin to address the risk of imbalance penalties, potential supply cuts, and forecast uncertainty.²⁵²

152. Even so, the Department argues that a supply reserve margin of two percent was reasonable for the time period of the February Event. That proposed margin is based on, but is slightly higher than, the actual supply reserve plans for the four-day weekend used by CenterPoint (1.8 percent), MERC (1.7 percent), and Great Plains (1.8 percent).²⁵³

153. Yet, Mr. King acknowledges that there is "no single figure for a supply reserve margin that can be universally applied," and that he "would not apply two percent outside of the specific facts and circumstances where it's being applied here."²⁵⁴ Further, he testified that he was not recommending what a gas utility in Minnesota should use for a supply reserve margin on a permanent basis.²⁵⁵

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

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

A: Yes.²⁵⁶

155. The Department's position, as expressed through Mr. King's opinion and testimony, suggests a result-oriented approach to the use of two percent as an appropriate supply reserve margin. The Administrative Law Judges have not read the Commission's charge to the parties or this tribunal as a directive to find and calculate disallowances. Rather, the Commission directed that this matter comprehensively consider the circumstances that arose during the February Event to determine if the Gas Utilities acted prudently, and if not, to identify the basis upon which disallowances should be calculated.

²⁵¹ *Id.*, Sch. 2 at 34-35, Figure 4.

²⁵² Ex. 506 at 56 (King Direct).

²⁵³ Ex. 507 at 34 (King Surrebuttal).

²⁵⁴ Evidentiary Hearing Tr. Vol. 2C at 50 (King).

²⁵⁵ *Id.* at 63.

²⁵⁶ *Id.* at 82.

156. Mr. King contends that two percent is a reasonable figure because it is roughly based on the actual experience of CenterPoint, MERC, and Great Plains during the first four days of the February Event. This is a narrow window through which to view the Gas Utilities' decisions, and reflects an after-the-fact review, rather than an assessment of the appropriateness of a forward-looking planning strategy. The Department asserts that a supply reserve margin should be deliberately determined and explainable.²⁵⁷ It further notes that failing to have some type of deliberate and explainable position for the supply reserve would essentially give the Gas Utilities unfettered discretion to purchase gas in excess of anticipated load and pass those costs onto ratepayers.²⁵⁸ That is not the case here. The facts before this tribunal are that the Gas Utilities, including Xcel, were purchasing for a long weekend with extremely cold weather forecasts and a significant concern about supply failures. In this environment, applying a rigid formula does not make sense.

157. In addressing load forecasting and supply reserve margin issues, CUB contends that Xcel over-forecasted load by approximately 6.26 percent on February 14, 2021, and 12.28 percent on February 17, 2021.²⁵⁹ CUB proposed disallowances of between \$1,513,383 and \$9,734,465, related to Xcel's forecasting, which it contends led Xcel to use less storage gas than it should have; CUB calculated the lesser number assuming a forecasting error is unreasonable only once it exceeds 10 percent; the greater number is calculated by assuming a forecasting error is unreasonable only once it exceeds 5 percent. CUB allowed for a 1.57-1.76 percent reserve margin.²⁶⁰ Ultimately, CUB recommends a disallowance of \$9,734,465.²⁶¹

158. Xcel counters that, given the significant uncertainties on both the demand side (due to weather variability) and the supply side (due to the risk of freeze-offs), prudent utility practice called for securing somewhat more gas than indicated by the load forecast.²⁶² Xcel notes that CUB started with the actual load Xcel experienced, and then provided a five to ten percent variance to account for "forecast error" or "reserve margin" of gas supply above forecast, a figure Xcel maintains is arbitrary.²⁶³ Xcel further argues that CUB's analysis relies on hindsight, and if it followed CUB's recommended course to purchase gas for the Presidents' Day weekend, Xcel would have had a substantial risk of being short of the necessary supplies to serve its customers.²⁶⁴

159. Under the circumstances of the February Event, Xcel's load forecasting and supply reserve margin were reasonable. Heading into the February Event, Minnesota was expected to experience extremely cold temperatures, and Xcel was already aware of the

²⁵⁷ Ex. 506 at 56 (King Direct); Ex. 507 at 32 (King Surrebuttal).

²⁵⁸ Evidentiary Hearing Tr. Vol. 2C at 80 (King).

²⁵⁹ Ex. 811 at 26 (Cebulko Surrebuttal).

²⁶⁰ *Id.* at 7, 36.

²⁶¹ Ex. 819 at 4 (Nelson Surrebuttal).

²⁶² Ex. 215 at 15, 18 (Levine Rebuttal) ("Given the substantial uncertainties facing the Company, which is tasked with ensuring that Xcel Energy's retail customers receive the gas supplies they need during a significant cold snap, . . . the Company acted reasonably when it procured those spot supplies in light of the market conditions.).

²⁶³ *Id.* at 38-39 (Levine Rebuttal).

²⁶⁴ *Id.* at 35-39.

potential for supply disruptions, leading to reasonable concerns about the risk to human life and property in the event Xcel did not have sufficient gas supply. Xcel was required to take gas ratably over the four-day period, and it faced the possibility of high penalties for imbalances. Xcel acted prudently based on the information it had on February 12.

160. To date, the Commission has not established specific parameters to govern the Gas Utilities' load forecasting procedures and outcomes, and has not set standards identifying a particular supply reserve margin figure as reasonable. The Commission is considering forward-looking strategies in another docket, and may wish to examine whether to establish such standards.

161. In this case, however, the evidence does not support a disallowance related to Xcel's load forecasting for February 13-16, the supply reserve margin used to purchase gas for the four-day weekend, or its purchases on February 12.

3. Intra-weekend Spot Gas Purchases

162. Xcel made two fixed price purchases during the Presidents' Day weekend.²⁶⁵ Purchases like these are not common because trading platforms are closed, but Xcel's has been able to make intra-weekend purchases at times in the past due to its knowledge of and relationships with gas sellers.²⁶⁶

163. Xcel made these purchases mid-day on February 13 and again February 15.²⁶⁷ Xcel made the purchases at that time because it had reports of supply failures, but it would not know the severity of the cuts and the impact to its operations until later in the evening when pipeline scheduling reports were issued.²⁶⁸ Given the high demand purchase market those mornings, Xcel was concerned that it would be unable to find additional gas supply if it waited until the evening, so it made mid-day purchases to ensure it had reliable supply.²⁶⁹

164. Xcel purchased 14,000 Dth of gas on February 13, for a fixed price of \$95.00/Dth, which was well below that day's Demarc and Ventura midpoints of \$231.57 and \$154.91, respectively.²⁷⁰ On February 15, Xcel purchased 8,280 Dth at a fixed price of \$157.00/Dth, slightly above the Ventura midpoint but below the Demarc midpoint.²⁷¹

165. The total cost of Xcel's intra-weekend purchases was \$2,820,990, and the Department has recommended disallowance of that amount.²⁷²

166. The Department maintains that it was not reasonable for Xcel to make these intra-weekend purchases. According to the Department, on February 14, Xcel used

²⁶⁵ Ex. 207 at 19-20 (Green Direct).

²⁶⁶ *Id.* at 7.

²⁶⁷ Ex. 204 at 23 (Derryberry Rebuttal).

²⁶⁸ *Id.*

²⁶⁹ *Id.* at 23-24.

²⁷⁰ Ex. 207 at 19 (Green Direct).

²⁷¹ *Id.* at 19-20.

²⁷² Ex. 506 at 64-66 (King Direct).

less storage than it had available because it had excess supply, such that Xcel had 766,354 Dth of available supply, an amount in excess of its actual load requirement of 710,041 Dth.²⁷³ The Department contends that, on February 15, the ratable requirements of Xcel's spot purchases on February 12 meant that it was expected to have excess supply available. Xcel ended up having 727,975 Dth versus its actual load requirement of 683,675 Dth.²⁷⁴

167. The Department argues that these purchases were based on unreliable load forecasts and the imprudent unavailability of Xcel's peaking plants. Xcel acknowledged, though it labeled it as speculation, that it might not have made these intra-weekend purchases if its peak shaving facilities had been available.²⁷⁵

168. Xcel counters that, at the times it made these purchases, it was operating in a highly dynamic and uncertain environment, it knew that supply cuts and freeze-offs were occurring, and Minnesota was experiencing subzero temperatures.²⁷⁶ Xcel notes that concerns were spread across the market and Xcel and other natural gas utilities did experience supply cuts over the weekend, creating significant demand for any available supply.²⁷⁷ Xcel also points out that the amount purchased on February 15 was less than the total undelivered gas that day.²⁷⁸

169. The Administrative Law Judges determine that Xcel's purchase of gas during the weekend was not imprudent. Xcel was operating in an environment of significant price and supply uncertainty, and made purchases to ensure reliable service while its customers were experiencing temperatures that could be life threatening. Though Xcel ended up with excess gas, it could not have known it would be in that position at the time it made the decision to make these purchases. Further, the Department's argument regarding the impact of Xcel's peaking plant availability on this decision presumes that Xcel would have run its peaking plants as a price mitigation measure, rather than as a means to balance its system and meet customer demand, an argument addressed in great detail later in this report.

170. The record does not support a determination that Xcel acted imprudently in making intra-weekend purchases and a disallowance is not warranted.

4. Spot Gas Purchases Made on February 16 for February 17

171. On February 16, 2021, Xcel purchased its gas to supply customers on February 17, the final day of the February Event.²⁷⁹

²⁷³ *Id.* at 64; Ex. 203 at Sch. 2 at 26 (Derryberry Direct).

²⁷⁴ Ex. 506 at 64–65 (King Direct); Ex. 203 at Sch. 2 at 26 (Derryberry Direct).

²⁷⁵ Ex. 506 at Sch. 13 at 2 (King Direct) (Xcel Response to DOC IR No. 47(b)).

²⁷⁶ Ex. 200 at 14-15 (Boughner Direct); Ex. 204 at 23-24 (Derryberry Rebuttal).

²⁷⁷ *Id.* at 25; Ex. 215 at 23-30 (Levine Rebuttal).

²⁷⁸ Ex. 207 at 19-20 (Green Direct).

²⁷⁹ *Id.* at 20.

172. Xcel's curtailment called on February 12 was set to last until February 18, and remained in effect.²⁸⁰ Moreover, that curtailment had now been in place for four days, informing the TESLA model load forecast for February 17.²⁸¹

173. Knowing of the continuing curtailment, and again planning for the maximum use of storage inventories, Xcel purchased sufficient gas supplies to meet its forecasted load and a reasonable "safety net" above that forecast.

174. Xcel's total planned supplies, forecasted load and percentage of supplies above the forecast for February 17 were:²⁸²

	Wednesday, Feb. 17th
<i>Total Planned Supplies</i>	655,946
<i>Forecasted Load</i>	644,628
<i>Percent Planned Supplies Exceeded Forecasted Load</i>	1.8

175. To meet these supply needs, Xcel purchased a total of 272,953 Dth of spot gas on February 16, including both index-priced and fixed-price gas.²⁸³

176. Xcel made the decision to meet a portion of its supply needs with fixed price gas over the morning of February 16, after considering a number of factors:²⁸⁴ The weather forecast for the next few days ahead showed warming trends;²⁸⁵ Xcel was buying gas for just the day ahead (as opposed to Xcel's purchases for the long weekend that had to cover four days);²⁸⁶ and based its gas supply experience, Xcel believed that the lingering market fear would cause prices to start higher, then move lower as the trading cycle progressed.²⁸⁷

177. To capture some of those anticipated lower costs for customers, on February 16 for the February 17 gas day, Xcel delayed a portion of its daily supply purchases as a limited hedge against the early index market.²⁸⁸ Prices did come down throughout the day's trading session.²⁸⁹

²⁸⁰ Ex. 204 at 26 (Derryberry Rebuttal).

²⁸¹ See Ex. 201 at 3 (Boughner Rebuttal); Ex. 204 at 4 (Derryberry Rebuttal).

²⁸² Ex. 203 at Sch. 2 at 26 (Derryberry Direct).

²⁸³ Ex. 207 at 20 (Green Direct).

²⁸⁴ Ex. 204 at 27 (Derryberry Rebuttal).

²⁸⁵ *Id.*

²⁸⁶ *Id.*

²⁸⁷ *Id.*

²⁸⁸ *Id.*

²⁸⁹ *Id.*

178. Xcel purchased approximately 50,000 Dth on February 16 at fixed prices between \$9 and \$95 for a weighted average of \$28.50/Dth, compared to the weighted average of index-based purchases of \$132.26/ Dth, a savings of over \$5,000,000.²⁹⁰

179. Xcel Energy had planned to fully curtail for February 17 and bought its daily gas on February 16 based on that plan.²⁹¹ However, Xcel witness Mr. Derryberry explained that:

The Company's daily purchases for February 17 were made early on February 16, when interruptible customers were expected to remain under curtailment. The Company had not yet determined that our interruptible customers would be released—in fact, our notices to interruptible customers called the curtailments through February 18 at 9:00 a.m. . . .

During the day, on February 17, after gas purchases had been made for the following day, the Company had information that the coldest weather and highest customer demand was receding and determined that it could release a portion of its interruptible customers at 6:00 p.m. on the 17th. Releasing those interruptible customers from curtailment was reasonable, since the Company knew that it had sufficient supplies. However, we did not release all of our interruptible customers until 9:00 a.m. February 18.²⁹²

180. The Department recommends a disallowance in the amount of \$7,176,393 for Xcel's February 16 purchases, based on its assessment that Xcel engaged in faulty load forecasting and due to the "early" release of curtailed customers.²⁹³ The recommended disallowance breaks down to \$4,351,593, related to load forecasting, and 2,824,800, related to the curtailment issues.²⁹⁴ CUB also challenges Xcel's load forecasting for February 17, and its concerns about curtailment are wrapped within its recommendation of a disallowance in the amount between \$1,513,383 and \$4,836,910.²⁹⁵

181. As noted above, Xcel has established that its load forecasts were reasonable, and this finding also applies to the load forecast for Gas Day February 17. Xcel's release of customers from curtailment was not expected on February 16, when Xcel bought gas for the next day, and Xcel factored that curtailment into its gas

²⁹⁰ *Id.* at 27-28.

²⁹¹ *Id.* at 26-27; Ex. 215 at 55-58 (Levine Rebuttal).

²⁹² Ex. 204 at 26-27 (Derryberry Rebuttal).

²⁹³ Ex. 506 at 71-73 (King Direct).

²⁹⁴ See Ex. 229 (Derryberry Errata); Ex. 507 at 45-46, 53 (King Surrebuttal). Note that the load forecasting disallowance figure is calculated in connection with the Department's claim that Xcel's peaking plants should have been available. The recommended disallowance figure for load forecasting on February 17 without consideration of the peaking plants is \$102,721. Ex. 507 at 53 (King Surrebuttal).

²⁹⁵ Ex. 811 at 5, 7 (Cebulko Surrebuttal); Ex. 819 at 7 (Nelson Surrebuttal) (noting removal of disallowance for release of interruptible customers from curtailment because the original disallowance recommendation double-counted load forecasting).

purchasing. The record does not support a disallowance related to gas purchases on February 16.

VII. Additional Disputed Issues

A. Maximization and Availability of Peaking

1. Background Regarding Peaking

182. The Commission's Order for Hearing directed that this proceeding address whether the Gas Utilities maximized the use of peaking capacity and, if not, to determine the financial impact. Further, specific to Xcel, the Commission requested development of the record regarding whether Xcel's maintenance and operation of its Wescott, Sibley, and Maplewood facilities resulted in financial impact.²⁹⁶

183. Xcel owns and operates three above-ground peaking plants: the Wescott Liquefied Natural Gas (LNG) plant (Wescott), and the Sibley and Maplewood Propane Air plants (Sibley) and (Maplewood).²⁹⁷

184. These plants essentially store LNG or liquid propane gas (LPG) that can be vaporized and injected into the system to help meet firm customer requirements in limited circumstances.²⁹⁸

185. The peaking plants are largely capacity resources, designed to be utilized on a limited basis to meet demand for the Company's firm customers in specified circumstances, either when conditions are near design day, or when there is an unanticipated supply shortage and no other gas is available.²⁹⁹ The Department has recognized the traditional role of peak-shaving plants in its comments prior to the initiation of this contested case.³⁰⁰

186. Xcel does not use its peaking plants often.³⁰¹ In the past ten years, Wescott has vaporized on a total of 146 days, with the last vaporization occurring in March 2019.³⁰² Even when dispatched, Wescott has been used sparingly – Wescott vaporized over 78,000 Dth a day (50 percent of its capacity) on only eight out of those 146 days of vaporization.³⁰³

²⁹⁶ Order for Hearing at 22.

²⁹⁷ Ex. 223 at 3 (Yehle Direct).

²⁹⁸ *Id.*

²⁹⁹ *Id.* at 3-4.

³⁰⁰ *Id.* at 3 ("peak shaving has historically been designed, and used in this market, as a reliability tool for the distribution system that supplements the system in the event of near design-day conditions or in response to other unexpected reliability issues" (citing Comments of the Minnesota Commerce Department, Division of Energy Resources, MPUC Docket No. G-999/CI-21-135 (May 10, 2021))).

³⁰¹ *Id.* at 12.

³⁰² *Id.* at 13; Ex. 226 at 10 (Yehle Rebuttal).

³⁰³ Ex. 226 at 10-11 (Yehle Rebuttal).

187. Sibley has a technical maximum single day withdrawal capacity of 46,000 Dth and Maplewood has a technical maximum single day withdrawal capacity of 44,000 Dth.³⁰⁴ In the past 10 years, Sibley has been dispatched on a total of 49 days and Maplewood has been dispatched on a total of 74 days.³⁰⁵ In that time, neither Sibley nor Maplewood has been dispatched at 50 percent or more of its daily withdrawal maximum – Sibley’s maximum dispatch in the past 10 years was 14,560 Dth/day on January 6, 2015, and Maplewood’s was 7,401 Dth/day in January 25, 2014.³⁰⁶ Sibley and Maplewood were last dispatched in February 2019.³⁰⁷

188. It is common for Xcel to use peaking plants on only a few days each year.³⁰⁸ Xcel did not run any of its peak-shaving plants during the 2019-20 heating season, as temperatures were generally warmer that winter, and peaking capacity was not needed.³⁰⁹

189. There is no dispute that Xcel’s peaking plants were not available during the February Event, as discussed in greater detail below. The Department contends that, had Xcel’s peaking plants been available, Xcel would have called upon peaking capacity to offset gas purchases due to high gas costs during the February Event.

190. The Department’s witness, Mr. King, testified that “Xcel identified in discovery that it has used its peaking plants for economic purposes in the past.”³¹⁰ A closer examination of the document on which Mr. King relies shows that this statement is not accurate. Xcel was asked to “describe any actions [it] would have done differently if the peaking plants were available.”³¹¹ Xcel responded:

Determining whether and to what extent the Company would have taken different actions had the peaking plants been available is impossible to determine. As the Department noted in Docket No. G999/CI-21-135, the plants are primarily used as a reliability tool for daily balancing. The Company does not have specific procedures in place to use the peak shaving plants for economic reasons and the plants have not been regularly used in this manner.³¹²

191. Mr. King’s interpretation of Xcel’s statement as an admission that it has used peaking to offset economic concerns goes far beyond the question and answer contained in the record.

³⁰⁴ Ex. 223 at 7 (Yehle Direct).

³⁰⁵ Ex. 226 at Sch. 1 at 3 (Yehle Rebuttal).

³⁰⁶ *Id.* at 11 (“During the time reported, neither Sibley nor Maplewood ever dispatched at half of their theoretical maximum, much less both plants dispatching half of their theoretical maximum on the same day.”).

³⁰⁷ *Id.* at 13.

³⁰⁸ *Id.* at Sch. 1 at 3-4.

³⁰⁹ *Id.* at 13.

³¹⁰ Ex. 506 at 95 (King Direct).

³¹¹ *Id.* at Sch. 13 at 1.

³¹² *Id.* at Sch 13 at 2.

192. Mr. King further opines that Xcel used its peaking capacity to offset purchases during the price spike that occurred in the 2017-18 New Year Event. Mr. King notes that Xcel ran its peaking plants during that event and contends that it is the best indicator for what Xcel would have done during the February Event if its peaking plants had been available.³¹³

193. Xcel responded to this argument through its witness, Mr. Derryberry, who noted the difficulty of reconstructing daily decisions made during an event that occurred four years before.³¹⁴ Mr. Derryberry also stated that the 2017-2018 New Year Event:

involved production freeze-offs focused in the Bakken production area of North Dakota. The Bakken is a major source of gas supply for the Ventura Hub, which is the Company's largest supply point providing more than half of our typical supplies. Experiencing freeze-offs and the related supply failures at our single largest supply point would have been extremely concerning to our gas supply team. I believe it is quite likely that the plants were run at that time to provide supplemental supply, as the team would have been concerned that it would not have been able to acquire adequate supplies from our other supply areas. The price spike to \$67 per MMBtu at Ventura is ample indication that Ventura supply was scarce.³¹⁵

194. Mr. King then opined that it was implausible that Xcel was concerned about supply issues in the Bakken, testifying that: "Xcel has not demonstrated that it encountered or anticipated significant supply failures or that it needed to run its peaking plants at the significant levels it did for reliability reasons during the 2017-18 New Year Event."³¹⁶ Mr. King relies on a supposition about the 2017-18 New Year Event, without evidence, and then purports to require Xcel to disprove his hypothesis. To be clear, this proceeding is not an investigation into Xcel's actions during the 2017-18 New Year Event. That event occurred years ago and shared only limited factual similarities with the February Event. Tying them together requires some evidence of a connection, and certainly more evidence than is present here.

195. Mr. King's opinions as to Xcel's actions during the 2017-28 New Year Event are speculative. The record establishes that Xcel ran its peaking plants during that event, but does not establish exactly why it did so. This record does not show Xcel has dispatched its peaking capacity in the past to offset high gas prices or how often it might

³¹³ Ex. 506 at 94-95 (King Direct) ("[T]he 2017-18 New Year Event was similar to the February Event in several ways including being an economic (daily price spike) event over a holiday weekend driven by less-than-Design Day weather. Loads during the 2017-18 New Year Event were actually slightly lower than those in the February Event. Based on the similarities between the events, I believe Xcel's actions during the 2017-18 New Year Event are the best indicator of what Xcel would have done with its peaking plants during the February Event.").

³¹⁴ Ex. 204 at 40 (Derryberry Rebuttal).

³¹⁵ *Id.* at 40-41.

³¹⁶ Ex. 507 at 43 (King Surrebuttal).

have done so, that it did so when it ran its peaking plants during the 2017-18 New Year Event, or that it would have done so during the February Event.

196. As noted above, Xcel uses peak-shaving plants for two primary purposes – injecting gas into its distribution system during design day, or near design day conditions, and injecting gas into the system to address unforeseen supply shortages, such as those due to colder-than-expected weather, when no other gas is immediately available.³¹⁷

197. While the weather was cold during the February Event, the Company did not reach near design day conditions.³¹⁸

198. The decision to dispatch a peak-shaving plant depends on a number of factors, most importantly the current state of the gas distribution system into which the gas from the plant would be injected. Essentially, the plants are designed to run when there is a place for the gas to go within the distribution system. If there is gas already in the system, pressures are operating correctly, and customers are drawing from the system as expected, injecting additional gas could lead to over-pressuring the downstream piping or the rest of the distribution system.³¹⁹

199. Situations in which capacity exists in the system to absorb additional gas from peaking plants may arise when Xcel experiences design day conditions or when there is too little gas to meet customer demand.³²⁰ Even in those situations, Xcel must still assess a number of factors, including the overall state of the distribution system, any downstream constraints from the plants (which vary among the Company's various plants), system pressures at multiple points in the system, and current temperatures and short-term temperature forecasts.³²¹

200. Xcel's witness Mr. Derryberry explained Xcel's use of peaking plants as follows:

[F]rom a gas supply planning perspective, our peak-shaving plants are a capacity resource, to be called on in near design day conditions or to address emergent reliability issues. The peak-shaving plants are not a primary supply resource or a supplement to our normal supply portfolio as they lack the inventory to perform that function. In plain English, we don't plan to run the peak-shaving plants first and then decide how much remaining gas we need to purchase. Rather, we buy gas first and then decide if we need to run the plants. . . . This is consistent with general gas utility practices.³²²

³¹⁷ Ex. 223 at 3-4 (Yehle Direct).

³¹⁸ Ex. 204 at 33 (Derryberry Rebuttal); Ex. 506 at 8 (King Direct).

³¹⁹ Evidentiary Hearing Tr. Vol. 1 at 164 (Yehle).

³²⁰ *Id.* at 164-65.

³²¹ *Id.* at 163-166; Evidentiary Hearing Tr. Vol. 2C at 54 (King).

³²² Ex. 204 at 31-32 (Derryberry Rebuttal).

201. Xcel argues that there is no evidence that the unavailability of its peaking plants had a financial impact during the February Event, stating:

The Company did not forecast near design day conditions and had obtained adequate supplies heading into the weekend. Therefore, neither of the circumstances that have historically informed the planning for and use of the plants was contemplated at the time Xcel Energy completed its supply purchases for the weekend. Whether or not the Company may have *later* decided to *run* its plants during the February Event in response to emergent conditions is irrelevant because that would have been an action taken *after* securing gas supply for the weekend. Simply running the plants as they are typically run – to meet emergent conditions or provide supply when other gas is not available – would not have impacted the Company’s gas supply planning and purchasing decisions at the time those decisions were made.³²³

202. CUB contends that when gas traded at \$15/Dth on February 11, Xcel should have expected the directionality of pricing and would have reduced gas purchases in order to dispatch peaking facilities, thereby reducing costs for ratepayers.³²⁴ Mr. Cebulko further opines that as of February 16, Xcel would have known that prices were at unprecedented levels and that it could have used peak-shaving facilities, had they been available, to offset this cost.³²⁵

203. There are several problems with this analysis. First, in its Order for Hearing, the Commission determined that prices below \$20/Dth “could reasonably be considered ‘normal’ under-recovery appropriate for inclusion in the automatic adjustment mechanism.”³²⁶ Yet CUB’s position would require Xcel to take action well below that threshold. Second, CUB’s position, along with that of the Department, would require Xcel to have planned to use its peak-shaving facilities in a manner at odds with its normal practices, and Xcel maintains, with practices across the utility industry.³²⁷ Third, both CUB and the Department have asserted that Xcel would have been required to use its peak shaving facilities in this manner to be deemed prudent. Put another way, according to CUB and the Department, there was only one choice available to Xcel, even though the standard of prudence recognizes that there may be a range of options that could be considered reasonable.

³²³ Xcel Initial Br. at 121 (Mar. 15, 2022) (eDocket No. 20223-183838-01).

³²⁴ Ex. 811 at 48-49, 54 (Cebulko Surrebuttal).

³²⁵ *Id.* at 49, 54.

³²⁶ Order for Hearing at 11, 20.

³²⁷ The Department contends that even after becoming aware of the enormous surge in gas prices, the Gas Utilities “could not be troubled to do anything other than continue business as usual.” Department’s Reply Br. at 3 (Mar. 25, 2022) (eDocket No. 20223-184159-07). The Gas Utilities are highly regulated entities providing an essential service in an environment that lacks significant flexibility as to the time gas is purchased, the amount that can be purchased or removed from storage, and the need to provide continuous service to firm customers. While there may be circumstances in which the Gas Utilities need to deviate from their standard practices, it would not be imprudent for Xcel to plan to operate its peaking facilities consistent with their purpose and typical usage.

204. Xcel has established that it would not have planned to run its peaking plants during the February Event in a manner that would have reduced its gas purchases. Planning gas purchases without planning to run its peaking plants would be consistent with Xcel's past operations and the way in which peaking plants are used in the natural gas industry, and would have been within the range of reasonable options available to Xcel. It is not reasonable to find that Xcel would have been required to plan to run the plants, in a manner outside its normal experience and standard utility practice, and that it was then required to reduce its purchase of gas to account for peaking plant volumes. Such a finding would be inconsistent with the standard governing prudence determinations.

205. Therefore, the record does not support finding that the unavailability of the peaking plants had a financial impact on ratepayers in connection with the February Event.

2. Wescott LNG Plant

206. The largest of the Company's three peaking plants is the Wescott LNG plant, located in Inver Grove Heights, Minnesota.³²⁸ Wescott was built in the 1970s.³²⁹ The plant has two storage vessels capable of storing approximately 2,145,000 Dth (i.e., approximately 26 million gallons) of LNG for injection into the Company's gas distribution system.³³⁰

207. The maximum single day withdrawal capacity of Wescott is 156,000 Dth due to the capacity of the downstream pipeline that serves the metropolitan Saint Paul area.³³¹

208. The Wescott plant was not available during the 2020-21 heating season, including during the February Event. Xcel suspended operations at Wescott after two unplanned releases of natural gas occurred at the facility, the first on December 31, 2020, and the second on January 4, 2021.³³² Xcel reported these to the Minnesota Office of Pipeline Safety (MNOPS) and the National Response Center.³³³

209. Xcel witness Steven Yehle testified as to how Wescott operates, stating:

During non-winter months, the Company purchases natural gas which is delivered to the plant. At Wescott, the Company liquefies this natural gas in a process that cools down the natural gas to approximately -260° F until it turns into a liquid form where it is stored in tanks. This process is known as liquefaction. The gas is liquefied because the volume of natural gas stored

³²⁸ Ex. 223 at 5 (Yehle Direct).

³²⁹ *Id.*

³³⁰ *Id.*

³³¹ *Id.* at 6.

³³² *Id.* at 15-16.

³³³ *Id.* at 16. The Department contends that Xcel's notification was untimely. An investigation into the timing of the notification and any determination of an appropriate consequences falls outside the scope of this proceeding.

in its liquid form is hundreds of times smaller than natural gas in a gaseous state. The gas is stored in a liquefied state until it is needed during the heating season. During the winter months, when Wescott is needed, the vaporization process heats the pressurized natural gas back up to a temperature to return it to its gaseous state so it can be injected back into the distribution system and delivered to our customers.

This means that the Wescott peaking plant has two separate and opposite processes—liquefaction, which cools the natural gas to a liquid form for storage in the tank, and then vaporization, heating the liquified gas and turning it back into a vapor state when leaving the tank. Shifting between these two processes is not simply a “flip of the switch.” Instead, the peaking plant focuses solely on the process of liquefaction in the non-heating season. Then early in the winter, the peaking plant “turns over” to prepare for the vaporization process.³³⁴

210. Preparing the plant for vaporization involves a testing process that requires a number of steps, and this testing process cannot begin until liquefaction has been completed.³³⁵ In 2020, the last day of liquefaction was on September 20, 2020.³³⁶ It takes approximately six to eight weeks to shut down the liquefaction equipment and perform maintenance and calibrations, and to troubleshoot repairs on the vaporization side.³³⁷ The two unplanned natural gas releases occurred when Xcel was in the midst of testing the full vaporization process, which is the final step required to turn the plant over from liquefaction to the vaporization process.³³⁸

211. After suspending operations after the unplanned releases, the Company undertook a comprehensive investigation of the cause of the unplanned releases.³³⁹

212. Xcel prepared a Root Cause Analysis of the releases,³⁴⁰ commissioned Hazard and Operability (HAZOP) and Layers of Protection Analyses (LOPA) for Wescott,³⁴¹ and completed a previously-initiated Gap Analysis with respect to all three plants.³⁴² Xcel also submitted one of the valves involved in the process that led to the releases for testing to determine the cause of its malfunction.³⁴³

³³⁴ *Id.* at 5.

³³⁵ Ex. 226 at 4 (Yehle Rebuttal).

³³⁶ *Id.* at 5.

³³⁷ *Id.*

³³⁸ *Id.* at 4-6; Ex. 218 at 15-16 (Martz Rebuttal).

³³⁹ Ex. 211 at 9-10 (Krug Rebuttal).; Ex. 218 at 31-32, 36-37 (Martz Rebuttal); Ex. 223 at 16 (Yehle Direct).

³⁴⁰ Ex. 218 at 16 (Martz Rebuttal); Ex. 502 at Sch. 10 (Polich Direct); Ex. 503 at Sch. 10 (Polich Direct (Trade Secret)).

³⁴¹ Ex. 218 at 35-36 (Martz Rebuttal); Ex. 502 at 19, Sch. 5 (Polich Direct); Ex. 503 at Sch. 5 (Polich Direct (Trade Secret)).

³⁴² Ex. 218 at 36-37 (Martz Rebuttal); Ex. 502 at 18, Sch. 11 (Polich Direct); Ex. 503 at Sch. 11 (Polich Direct (Trade Secret)).

³⁴³ Ex. 218 at Sch. 1 (Martz Rebuttal); Ex. 219 at Sch. 1 (Martz Rebuttal (Trade Secret)).

213. 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 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.³⁴⁴

214. Xcel also worked with MNOPS during this time.³⁴⁵ MNOPS required that a number of actions to be taken prior to any plant maintenance, configuration or repair, and a separate list of actions to be taken prior to any operation of the facility.³⁴⁶ Ultimately, Wescott was returned to service in December 2021.³⁴⁷

215. Based on its investigation, Xcel determined that the releases were caused by the failure of one of the LNG pumps to stop pumping when LNG flow to the vaporizer had stopped. The pump should have stopped running when a temperature control valve on the piping downstream of the vaporizer closed in order to protect the downstream piping due to low temperature of the LNG coming out of the vaporizer, but the pump continued to run.³⁴⁸

216. The pump had been installed twenty years earlier, and had a capacity greater than that of the downstream piping.³⁴⁹ Xcel had not experienced a similar incident at Wescott in the 20 years since the pumps had been installed.³⁵⁰

217. Xcel also determined that the LNG temperature flowing into the vaporizer was too low because insufficient hot glycol (WEG) was flowing into the vaporization system.³⁵¹ WEG is the substance that heats the LNG, causing it to heat up and vaporize.³⁵²

218. The increased pressure resulted because the pumps continued to pump LNG into a chamber that was already full, as no LNG could leave the chamber after the temperature control valve downstream of the vaporizer had closed.³⁵³ This caused the pressure relief valves to open, releasing natural gas into the atmosphere.³⁵⁴ The pressure relief valves operated and performed as designed, preventing a pipe rupture and potentially a much more catastrophic event.³⁵⁵

219. Xcel also eventually determined that a valve that controls the flow of the WEG was not opening properly in response to signals from the plant's operating

³⁴⁴ Ex. 502 at 20 (Polich Direct).

³⁴⁵ Ex. 223, at 19-20 (Yehle Direct).

³⁴⁶ Ex. 224 at Sch. 4 at 3-4 (Yehle Direct (Highly Confidential Trade Secret)).

³⁴⁷ Ex. 226 at 7 (Yehle Rebuttal).

³⁴⁸ Ex. 218 at 16 (Martz Rebuttal).

³⁴⁹ *Id.* at 25.

³⁵⁰ *Id.* at 17.

³⁵¹ *Id.* at 28.

³⁵² *Id.* at 8.

³⁵³ *Id.* at 24.

³⁵⁴ *Id.*

³⁵⁵ Ex. 504 at 12 (Polich Surrebuttal).

system.³⁵⁶ The valve was located inside of the WEG system, and the actual position of the valve was not discernable during operation.³⁵⁷

220. Once the Wescott plant was shut down and the WEG system emptied, the valve was removed and sent to an outside consulting firm for analysis.³⁵⁸ This phase of the investigation determined that the valve coating had deteriorated, which had caused the valve to operate improperly.³⁵⁹ As a result, the valve was not responding consistently to command signals from the plant's operating system, Citect.³⁶⁰ Citect showed only the commanded position of the valve, not the actual position of the valve.³⁶¹

221. The Department disagrees with the root cause analysis performed by Xcel. The Department contends that a "root cause" is the earliest factor in a causal chain, the removal of which would prevent the failure from occurring.³⁶² The Department asserts that root cause of the unplanned releases was the failure of the WEG supply valve to supply hot WEG to the vaporizer.³⁶³ The Department contends the unplanned releases also resulted because Xcel decided to quickly restart the facility, and did not provide enough time for the LNG pump to cooldown between trips.³⁶⁴ The Department maintains that Xcel failed to periodically test this aspect of its system to ensure proper operation.³⁶⁵ The Department's witness, Richard Polich, opined that it would have been possible for Xcel to test the valve for proper operation using common household tools like pipe and crescent wrenches.³⁶⁶

222. Xcel was in the process of testing the Wescott facility's operation at the time the unplanned releases occurred.³⁶⁷ Xcel notes that the Wescott facility is a complex system and that the cause of a problem often is not immediately evident.³⁶⁸ Xcel points out that it had not previously experienced the malfunction that occurred at Wescott during the 20 years after installation of the pump, and argues this shows that the facility was not imprudently maintained.³⁶⁹ It notes that Wescott successfully vaporized on numerous

³⁵⁶ Ex. 218 at 22-23 (Martz Rebuttal). A diagram showing a simplified schematic of the Wescott system at issue here can be found at Ex. 219 at 8 (Martz Rebuttal (Trade Secret)).

³⁵⁷ Ex. 218 at 22-23 (Martz Rebuttal).

³⁵⁸ *Id.* at 23, Sch. 1; Ex. 219 at Sch. 1 at 2 (Martz Rebuttal (Trade Secret)).

³⁵⁹ Ex. 218 at 23, Sch. 1 (Martz Rebuttal); Ex. 219 at Sch. 1 at 2 (Martz Rebuttal (Trade Secret)).

³⁶⁰ Ex. 218 at 21-22 (Martz Rebuttal).

³⁶¹ *Id.* at 22-23.

³⁶² Ex. 504 at 2-3 (Polich Surrebuttal).

³⁶³ *Id.* at 13-14.

³⁶⁴ *Id.* at 26-27.

³⁶⁵ Ex. 504 at 22 (Polich Surrebuttal).

³⁶⁶ Evidentiary Hearing Tr. Vol. 2B at 18-19 (Polich) ("And my experience has been in this that you could essentially use common wrenches that people have in their house – that sometimes they have in their house, such as a pipe wrench or a crescent wrench, Because the shape of that top of that valve stem is basically square. And that would allow you to put a wrench on that to be able to manually operate that valve. And I have not been in a power plant or generation – or a plant of any type that you can't find a pipe wrench or a crescent wrench.")

³⁶⁷ Ex. 223 at 15-16 (Yehle Direct).

³⁶⁸ Ex. 218 at 11-14, 17 (Martz Rebuttal).

³⁶⁹ *Id.* at 17.

occasions in 2019.³⁷⁰ Xcel also maintains, as explained above, that it would not have been able to examine the pump without taking apart a portion of the WEG piping system.³⁷¹

223. CUB contends that Xcel is required to show that Wescott's "unavailability due to a safety issue was outside of its control."³⁷² This is not the standard that applies here. Rather, the question posed by the Order for Hearing is whether Xcel's maintenance and operation of its peaking facilities resulted in financial impact.³⁷³ This inquiry arises in the context of a prudency determination and, while Xcel bears the burden of proof to establish its actions were prudent, the standard is not one of strict liability or "but for" causation.

224. The Administrative Law Judges determine that the operational issues at the Wescott facility did not have a financial impact on this case. Xcel has established that it uses peaking plants when conditions are near or at Design Day and when needed in order to meet customer demand when no other gas is immediately available. Xcel has established that these circumstances did not exist at the times that it was purchasing gas related to the February Event, and it would not have planned to run its peaking plants and reduce gas purchases in anticipation of these additional volumes. Therefore, the unavailability of the Wescott plant did not impact the level of extraordinary gas costs Xcel incurred.

225. The Administrative Law Judges note that this proceeding addresses only the prudency of the gas costs incurred in connection with the February Event and the events that led Xcel to remove the plant from operations as of the time of the February Event. It is not a larger-scale examination of the prudency of Xcel's operations generally as related to its peaking plants, which could occur in a rate case or other inquiry. The record contains information related to other concerns found at the Wescott plant. This Report makes no finding as to those issues, as such an inquiry would exceed the scope of this case.

3. Sibley and Maplewood Propane Air Plants

226. Xcel owns two smaller facilities that can be dispatched to inject propane, which must be mixed with air, into its natural gas system.³⁷⁴ The Sibley plant is located in

³⁷⁰ *Id.* at 23.

³⁷¹ *Id.* at 22-23 ("After thorough investigation, the Company found that the valve itself was not responding to the commands sent from the control system. The valve does not have a digital position sensor which sends information to the control room based on actual, physical position. At the time the Wescott plant was designed, analog-only signals were in common use. Unlike digital positioners, which came into use more recently, analog signals are based on what the valve was told to do, rather than the actual position of the valve. So, from the control room, the plant operator could only see what the valve had been instructed to do, not its actual position.... In order to physical[ly] verify the actual position of the valve, plant personnel would have needed to evacuate the WEG system and remove a portion of the WEG system piping.").

³⁷² Ex. 801 at 93 (Cebulko Direct).

³⁷³ Order for Hearing at 22.

³⁷⁴ Ex. 223 at 6 (Yehle Direct).

Mendota, Minnesota, and the Maplewood plant is located in Maplewood, Minnesota.³⁷⁵ Both of these plants, which were built in the 1950s,³⁷⁶ are located in suburban areas which have developed around the plants.³⁷⁷

227. Sibley can store approximately 114,000 Dth equivalent of propane, and Maplewood can store approximately 124,000 Dth equivalent of propane.³⁷⁸ Sibley's maximum single day withdrawal is 46,000 Dth equivalent, and Maplewood's is 44,000 Dth. These limitations are primarily related to the limits of the downstream pipeline system.³⁷⁹

228. Sibley and Maplewood are used sparingly as capacity resources, and may go for long periods of time without use, sometimes for entire heating seasons.³⁸⁰

229. Sibley and Maplewood also have special considerations that are unique to propane plants, most notably the requirement that the propane must be mixed with air before being injected into the natural gas system, which is required because propane alone and natural gas burn at different intensities. If the propane-air mixture is not correct, operational and safety issues can result.³⁸¹

230. Following the January 4 natural gas release at Wescott, Xcel took the Maplewood and Sibley facilities out of service.³⁸²

231. Xcel maintains it did so in order to comply with federal pipeline regulations.³⁸³ Xcel contends it also was adhering to American Petroleum Institute Recommended Practice 1173, requiring the application of pipeline safety management systems (PSMS) when operating systems like the Company's peak-shaving plants, and the performance of incident evaluation and root cause analysis when abnormal operating conditions or events occur.³⁸⁴

232. Following the suspension of operations at all three peak-shaving plants, the Company also undertook an evaluation of conditions at Sibley and Maplewood by performing HAZOP studies at both plants.³⁸⁵ The reports were finalized in September 2021.³⁸⁶

³⁷⁵ *Id.*

³⁷⁶ Ex. 218 at 36 (Martz Rebuttal).

³⁷⁷ *Id.* at 14, 32-35.

³⁷⁸ Ex. 223 at 6 (Yehle Direct).

³⁷⁹ *Id.* at 7.

³⁸⁰ Ex. 218 at 13-14 (Martz Rebuttal).

³⁸¹ *Id.* at 13.

³⁸² *Id.* at 16; Ex. 223 at 16 (Yehle Direct); *see also* Ex. 212 at 9 (Krug Rebuttal) (“[I]t took time to conduct a root cause analysis and determine the cause of [the] unplanned releases. As we did that analysis, we did not know if the safety issue at the Wescott plant implicated the safety of the Sibley and Maplewood plants.”).

³⁸³ Ex. 218 at 31-32 (Martz Rebuttal).

³⁸⁴ *Id.* at 32.

³⁸⁵ *Id.* at 35-36; Ex. 223 at 18 (Yehle Direct).

³⁸⁶ Ex. 218 at 5 (Martz Rebuttal).

233. The Department agrees that it was prudent to take Sibley and Maplewood out of service after the unplanned releases at Wescott.³⁸⁷ The Department, however, contends that Xcel's failure to timely evaluate the cause of the Wescott failure and review its propane operations led Xcel to imprudently to remove Maplewood and Sibley from service for the remainder of the 2021 heating season.³⁸⁸

234. The Department's objection related to Sibley and Maplewood is outside the scope of this proceeding. This matter is a prudency review related to costs incurred in connection with gas procured to serve customers on February 13-17, 2021. Therefore, the question presented is whether Xcel's actions with regard to the Sibley and Maplewood facilities had a financial impact in connection with that five-day period. An examination of prudency related to the remainder of the 2021 winter heating season does not fall within the issues identified in the Order for Hearing.

235. To the extent that there are larger questions related to the prudency of Xcel's operation and maintenance of the Sibley and Maplewood plants, Xcel has indicated that it anticipates these issues will be addressed in the Company's recently-filed rate case.³⁸⁹ This Report does not address those issues or contain any recommendations related to matters that may arise within that rate case.

236. The Department agrees that Xcel prudently removed the Sibley and Maplewood plants from service immediately after issues arose at Wescott. Though Sibley and Maplewood remained out of service five-to-six weeks later, when the February Event occurred, the record does not support finding that there was a financial impact on ratepayers. Xcel has established it would not have planned to use these facilities in a manner that would have reduced the amount of gas it purchased during the February Event. Further, the Department's concern that these plants should not have remained out of service for the remainder of the heating season exceeds the scope of the issues identified in the Order for Hearing.

B. Hedging

237. In response to the Commission's direction regarding record development as to any other issues not enumerated,³⁹⁰ the OAG addressed the Gas Utilities' use of hedging.

238. "Hedging" is a process by which a person or organization takes a "tactical action . . . with the intent of reducing the risk of losing money."³⁹¹ In the context of purchasing natural gas, hedging can take the form of physical or financial hedging.³⁹² An example of physical hedging is purchasing natural gas during the summer when prices

³⁸⁷ Ex. 504 at 24 (Polich Surrebuttal).

³⁸⁸ *Id.* at 24-25.

³⁸⁹ Ex. 218 at 35 (Martz Rebuttal); Ex. 212 at 23-24 (Krug Rebuttal).

³⁹⁰ Order for Hearing at 23.

³⁹¹ Ex. 600 at 3 (Lebens Direct).

³⁹² *Id.*

are low and storing it for later use during the winter.³⁹³ Financial hedging often involves derivatives, such as options and futures contracts.³⁹⁴

239. Xcel's practices regarding hedging are subject to review and approval by the Commission.³⁹⁵ Without approval, Xcel is unable to recover the costs of the financial instruments purchased under its hedging plans, unless it receives a rule variance.³⁹⁶ Xcel also provides details on its hedging plans and hedging activity each year with its AAA filing.³⁹⁷

240. Xcel uses financial instruments to hedge against monthly natural gas commodity price volatility.³⁹⁸ These hedges are designed to protect against longer-term trends in rising gas prices, not spikes in the daily market.³⁹⁹ Xcel's financial hedging strategy calls for hedging transactions to be concluded between April and October for the upcoming winter.⁴⁰⁰ This timeframe allows the Company to analyze market data regarding production trends, demand trends, and storage inventory levels in making its hedging decisions.⁴⁰¹ The seasonal nature of the strategy provides a level of price risk protection while maintaining a balance between market premiums and overall plan costs.⁴⁰²

241. Xcel's currently approved hedging plan limits it to hedging no more than 50 percent of its annual expected winter requirements (through either physical storage or financial hedging), and no more than 25 percent of our annual expected winter requirements through financial instruments.⁴⁰³ Xcel maintains that 50 percent is a prudent target level when balancing costs and benefits of financial hedging programs; these financial instruments have been quite costly in the past and, in Xcel's view, in many years, there is not enough gas price market volatility to make them beneficial.⁴⁰⁴

242. The Department's witness, Mr. King, testified that hedging tools generally do not provide daily price spike mitigation. Rather, Mr. King testified that hedging tools, if in place, could be valuable to mitigate against consistent upward market moves, "rather

³⁹³ *Id.*

³⁹⁴ *Id.*

³⁹⁵ See *In re 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*, MPUC Docket No. G-002/M-19-703, Order at 1 (Feb. 12, 2020).

³⁹⁶ Ex. 211 at 17 (Krug Direct).

³⁹⁷ See *id.* at Sch. 3 at 13-17, Sch. 4 at 13-17.

³⁹⁸ *Id.* at 17 (Krug Direct).

³⁹⁹ Ex. 203 at Sch. 2 at 11 (Derryberry Direct).

⁴⁰⁰ *Id.*

⁴⁰¹ *Id.*

⁴⁰² *Id.* at 11-12.

⁴⁰³ *Id.* at 11; *In re 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*, MPUC Docket No. G-002/M-19-703, Order at 1 (Feb. 12, 2020).

⁴⁰⁴ Ex. 203 at Sch. 2 at 11 (Derryberry Direct).

than a transient spike.”⁴⁰⁵ “Financial hedges typically point to monthly FOM prices as opposed to daily prices.”⁴⁰⁶

243. The OAG asserts, however, that there were “potential” hedges that the Gas Utilities “may have been able to pursue,” either during February 2021, or even year or more ahead of time, which “could have mitigated some of the extraordinary costs” incurred.⁴⁰⁷

244. The OAG contends that the Gas Utilities should have implemented price ceilings and price floors in their swing contracts to ensure that prices remained inside the expected range of prices, which it contends would have managed price risk in nearly all situations.⁴⁰⁸ Mr. Lebens suggested the utilities could have pursued “customizable [OTC] contracts that cap the maximum price that they would have paid.”⁴⁰⁹ Finally, Mr. Lebens suggests that the utilities could have used Weather Futures and Options to hedge price risk during the February Market Event.⁴¹⁰ According to the OAG, the utilities hedging decisions, spanning several years, contributed to the extraordinary gas costs incurred during the February Event and were not prudent.⁴¹¹

245. The OAG recommended that if the Commission found that the Gas Utilities should have both: (1) negotiated collars into their swing contracts; and (2) should not have been exposed to the risk of spot market prices, the Commission should disallow the full \$661,537,779 in extraordinary gas costs for all of the Gas Utilities.⁴¹² Alternatively, the OAG opined that a reasonable disallowance based on actual hedges would be in the range of approximately \$71 million to \$92 million, across all four entities.⁴¹³

246. During the evidentiary hearing, Mr. Lebens testified that he was not aware of any Commission proceeding that directed the utilities to engage in the kind of financial hedging that he advocates the utilities had to do to be found prudent.⁴¹⁴ Mr. Lebens further testified that he is not aware of any proceeding before the Commission in which the Commission has discussed the financial hedging strategies he opines on or indicated that such hedging strategies would bear on prudence.⁴¹⁵

⁴⁰⁵ Ex. 506 at 23 (King Direct).

⁴⁰⁶ *Id.*

⁴⁰⁷ Ex. 600 at 2 (Lebens Direct).

⁴⁰⁸ See *id.* at 17-18 (opining that hedged swing contracts would essentially be sold at the top fully maximizing that potential value of the hedge, with no specific decisions required, other than the utilities planning ahead by putting hedged swing contracts in place in advance).

⁴⁰⁹ *Id.* at 6.

⁴¹⁰ *Id.*

⁴¹¹ Ex. 604 (Lebens Written Summary of Pre-Filed Testimony).

⁴¹² Ex. 600 at 43 (Lebens Direct).

⁴¹³ *Id.* at 44.

⁴¹⁴ Evidentiary Hearing Tr. Vol. 3 at 50-51 (Lebens).

⁴¹⁵ *Id.* at 51.

247. Mr. Lebens does not have experience developing hedging strategy, trading physical natural gas, trading financial hedges for a natural gas utility, or negotiating hedging contracts.⁴¹⁶

248. Mr. Lebens was not aware of any daily, weekly, or short-term hedges or exchange-traded hedges at Ventura or Demarc that were traded in the market during 2021.⁴¹⁷ In his testimony, Mr. Lebens did not identify any OTC products that could have been utilized to hedge against gas price spikes at either Northern-Demarc or Northern-Ventura. Rather, he requested that the Gas Utilities identify such products that he cannot price or quantify.⁴¹⁸

249. Xcel responds to the OAG's analysis by relying on the testimony of expert witness, Richard Smead. Mr. Smead opined that the OAG's proposed hedging strategy is based on "unwarranted and highly speculative assumptions, lacks supporting facts, and illustrates a limited and at times incorrect understanding of the market for hedging instruments."⁴¹⁹

250. Mr. Smead notes that the OAG discussed the purchase and sale of options to trade gas futures contracts at a specified price on the Chicago Mercantile Exchange (CME) at the Henry Hub (Henry), which is in Erath, Louisiana, over 1,000 miles away from the Minnesota market.⁴²⁰ In order for the utilities to obtain price protection, a meaningful strategy would relate to prices at Ventura and Demarc, as the Minnesota markets were impacted by the loss of supply in the South Central and Southwest regions, primarily Texas and Oklahoma, not by the national or Louisiana market represented by Henry.⁴²¹

251. Mr. Smead also noted that one of the OAG's recommendations relied on contracts available in February 2021, but that were for the delivery of March gas.⁴²²

⁴¹⁶ *Id.* at 38; *see also* Ex. 137 (OAG Response to CenterPoint Energy Information Request No. 11) ("Mr. Lebens does not have experience implementing a hedging strategy for a regulated utility nor has he previously evaluated the implementation of a hedging strategy for a regulated utility in testimony outside of this proceeding and its related dockets.").

⁴¹⁷ Ex. 600 at 8, 10 (Lebens Direct).

⁴¹⁸ *Id.* at 10-11.

⁴¹⁹ Ex. 101 at 2 (Smead Rebuttal).

⁴²⁰ *Id.* 4-6.

⁴²¹ *Id.* at 5, 8; *see also id.* at 10 ("Mr. Lebens appears to be saying that if the Joint Utilities had bought their gas (delivered) at their supply points at Demarc or Ventura, but priced it based on a point irrelevant to those points, the gas could have cost less than it did during this single crisis. . . . Here, the prices at Demarc and Ventura reflect the prices of gas feeding into NNG from areas primarily in Texas, Oklahoma, North Dakota, and Canada, *plus* the cost of transporting that gas to Demarc and Ventura, plus or minus whatever competitive price dynamics to those points are specifically taking place *at those points*. There is no connection to Henry, and Henry prices in no way reflect the costs or market dynamics involved in getting gas to Demarc or Ventura.").

⁴²² Ex. 101 at 20 (Smead Rebuttal) ("Most importantly, the example relates to *March* gas, not February, so the prices plotted could not possibly have any bearing on the price of February purchases."); *see also* Evidentiary Hearing Tr. Vol. 3 at 19 (Lebens).

252. Mr. Smead criticized the OAG's position that the Gas Utilities could have used collars to mitigate price risk. Mr. Smead stated:

[A]ll of the option examples [the OAG] uses to theorize about collars are CME options to buy *futures contracts* at Henry, not options to buy or sell actual gas supply at Demarc or Ventura. Not only are Henry transactions irrelevant to Demarc and Ventura, but such options can only be exercised to buy a futures contract *before the month to which the futures contract would apply*. They cannot be exercised in the middle of a month (e.g., February 8 for February supply) when an unanticipated spike in gas cost takes place after the start of the month.

Second, the floor price, or put, carries with it the obligation to buy the subject futures contract even if the floor price is well above the current market price. This can force the buyer to take excess gas that could well have to be disposed of at lower prices—sometimes significantly lower—potentially leading to substantial losses that would then be borne by customers. If engaging in such collars were business as usual, at a level to accommodate all of the utilities' swing gas, these additional costs would happen frequently over many years, leading to very large cumulative ratepayer costs, and still not protect against a totally unprecedented event such as Winter Storm Uri.⁴²³

253. As for weather derivatives, Mr. Smead noted that the massive price spikes were not driven by changes in the weather in Minnesota, but by weather impacts far away in Texas and Oklahoma, and by the collapse of the power grid in Texas.⁴²⁴ He opines that “weather products provide a hedge against variations of heating degree-days from normal, an approach often employed by utilities to normalize their revenues against weather changes, primarily oriented toward consumption volumes, not prices,” and that weather derivatives would not have mitigated prices during the February Event.⁴²⁵

254. Mr. Smead further opined that “the various suggestions made in the OAG testimony are either a highly risky commodity-speculation strategy, the search for price-protection tools that simply do not exist, or the commitment to price-protection tools that would be prohibitively expensive. Thus, none of the suggestions are approaches that a reasonable utility would pursue.”⁴²⁶

255. The record in this case does not support finding that Xcel should have engaged in the hedging strategies urged by the OAG. These strategies are based on ideas about hedging that are untethered to actual facts related to the market for natural gas and would have required Xcel to engage in highly speculative transactions, or identify products that were unavailable or do not exist. The OAG's hedging strategies also would have required Xcel to take actions long before the February Event occurred, without any

⁴²³ *Id.* at 13.

⁴²⁴ *Id.* at 18-19.

⁴²⁵ *Id.* at 18.

⁴²⁶ *Id.* at 3.

knowledge that a price spike of this magnitude would occur. This is not consistent with the standard for assessing prudence. No disallowance is warranted related to the OAG's proposals regarding hedging.

C. Maximization of Storage

256. As described above, on each day of the February Event, Xcel planned to withdraw the maximum allowable amount from storage and nominated withdrawals at those volumes.⁴²⁷

257. Because Xcel planned to withdraw its maximum allowance from storage, it reduced its planned daily gas purchases for the February Event by those maximum withdrawal volumes.⁴²⁸

258. After those purchases were made and at the end of each day during the pricing event, Xcel had more gas supply available than customers ultimately consumed.⁴²⁹ Xcel then used its storage account to balance flowing supplies and demand and avoid substantial pipeline penalties.⁴³⁰

259. CUB contends that Xcel's use of storage was imprudent, an argument tied to its assertion that Xcel over-forecast load for the February Event and its recommended disallowance on that basis. Though Xcel maximized storage nominations, CUB asserts this does not equate to maximizing storage utilization. CUB maintains that Xcel reduced storage withdrawals by 18 percent on February 14, and by 22 percent on February 17.⁴³¹ CUB also alleges that Xcel over-procured spot gas for every day of the long weekend, and as a result "the need to reduce storage withdrawals over each day of the weekend was high and reached a maximum of 38 percent in storage withdrawal reductions on February 16."⁴³² The Department makes a similar argument, noting that Xcel did not maximize its available storage on February 17. Although Xcel fully nominated storage, the Department contends this is not the same as reducing planned spot purchases for the maximum withdrawal capability.⁴³³ The Department recommends a disallowance of \$4,051,652, related to Xcel's use of storage.⁴³⁴

260. As addressed above, Xcel had a high volume of storage gas available leading into the February Event, and the record supports finding that Xcel made gas purchasing decisions for the February Event planning to maximize storage withdrawals. Xcel ultimately used less storage gas than planned, but this does not show that Xcel acted

⁴²⁷ Ex. 203 at Sch. 2 at 32 (Derryberry Direct); Ex. 214 at Sch. 2 at ¶¶62-64 (Levine Direct).

⁴²⁸ Ex. 203 at Sch. 2 at 32 (Derryberry Direct); Ex. 204 at 30 (Derryberry Rebuttal); Ex. 214 at Sch. 2 at ¶64 (Levine Direct).

⁴²⁹ Ex. 203 at Sch. 2 at 32 (Derryberry Direct).

⁴³⁰ *Id.* at Sch. 2 at 33-34.

⁴³¹ Ex. 801 at 54 (Cebulko Direct).

⁴³² *Id.*

⁴³³ Ex. 506 at 84-85 (King Direct).

⁴³⁴ *Id.* at 85.

imprudently when making gas purchasing decisions. Instead, the record supports finding that Xcel prudently planned for and used storage in connection with the February Event.

VIII. Undisputed Issues

261. The Commission's Order for Hearing directed that certain issues be addressed in this Report.⁴³⁵ Ultimately, some of those issues did not result in disputes between the parties. This section addresses matters as to which there is no dispute, or which are largely undisputed.

A. Geographic Diversity of Gas Supply

262. The Commission directed that this proceeding address whether the Gas Utilities had sufficient geographic diversity of supply, and if not, to determine the impact.⁴³⁶

263. Geographic diversity of supply refers to gas utilities' ability to acquire gas supply from a variety of locations and is ultimately tied to the transportation arrangements they hold with pipelines. The Gas Utilities hold sufficient firm transportation with pipelines to meet their Design Day needs, and those arrangements are with a variety of pipelines which connect with the Gas Utilities' distribution systems. These transportation arrangements specify receipt points, which are the points at which the Gas Utilities have rights to receive gas on the pipeline and then ship it to the delivery point (e.g., the point at which utility system connects with the pipeline).⁴³⁷

264. In any particular area, the pipelines that exist are the result of many years of history based on the demand at major market centers and production from supply basins (which shifted significantly because the shale revolution). Pipelines exist to move gas from where it is produced to where it is consumed, and the consumers of gas (e.g., LDCs) are the entities which primarily contract with pipelines for that transportation.⁴³⁸

265. Transportation contracts are generally long-term (meaning several years). Pipelines have processes for offering available capacity in a nondiscriminatory way, and shippers can offer to sell their existing transportation to interested buyers in a secondary market (called capacity release). Shippers (buyers of transportation service from pipelines) typically endeavor to obtain the most favorable commercial terms for their needs by leveraging options against each other. If a shipper is able to demonstrate the ability to bypass a pipeline, the pipeline will typically offer a discounted rate to retain the shipper.⁴³⁹

⁴³⁵ Order for Hearing at 22-23.

⁴³⁶ *Id.* at 22.

⁴³⁷ Ex. 506 at 42 (King Direct).

⁴³⁸ *Id.*

⁴³⁹ *Id.* at 42-43.

266. The Gas Utilities' transportation capacity is reviewed through their Contract Demand Entitlement filings.⁴⁴⁰

267. As noted above, Xcel contracts with approximately 30 different entities for its natural gas supplies.⁴⁴¹

268. Xcel transports the majority of its natural gas supply on NNG, Viking Transmission (Viking), and WBI Transmission Inc (WBI) pipelines, which are the only interstate pipelines directly connected to Xcel's distribution systems.⁴⁴² Xcel also relies on Northern Border Pipeline Company (Northern Border), Great Lakes Gas Transmission (GLGT), and ANR Pipeline Company (ANR-P), which are not directly connected to Xcel's distribution systems.⁴⁴³

269. During the February Event, Xcel's access to this array of pipelines allowed it to purchase approximately 590,000 Dth of gas supply at the Emerson and Chicago Hubs where gas prices were lower.⁴⁴⁴ Xcel was able to save an estimated \$58 million compared to potential purchases at Ventura.⁴⁴⁵

270. Xcel also holds natural gas storage services on NNG, ANR-P, and ANR Storage Company (ANR-S).⁴⁴⁶ Storage acts as a physical hedge to purchasing daily spot gas.⁴⁴⁷

271. Gas Utilities are limited by their available transportation.⁴⁴⁸ If alternative pipeline capacity is not readily available, building additional capacity would require ongoing and significant fixed costs. These additional fixed costs would need to be justified on a cost basis.⁴⁴⁹ Additional geographic diversity of supply cannot easily be obtained.⁴⁵⁰

272. Xcel used the geographic diversity of its capacity resources to purchase spot gas from four different hubs, resulting in the lowest weighted average cost of gas of the Gas Utilities during the February Event.⁴⁵¹

273. No other party disputed the reasonableness of Xcel's geographic diversity of supply. Xcel has shown that its geographic diversity was reasonable and prudent.

⁴⁴⁰ *Id.* at 42.

⁴⁴¹ Ex. 203 at 5 (Derryberry Direct).

⁴⁴² *Id.* at 3-4.

⁴⁴³ *Id.* at 4.

⁴⁴⁴ *Id.* at Sch. 2 at 37.

⁴⁴⁵ *Id.*

⁴⁴⁶ Ex. 203 at 4.

⁴⁴⁷ *See id.* at Sch. 2 at 11.

⁴⁴⁸ Ex. 506 at 48 (King Direct).

⁴⁴⁹ *Id.* at 49.

⁴⁵⁰ *Id.*

⁴⁵¹ *Id.* at 48.

B. Fixed-Price Contracts

274. The Commission directed that this proceeding address whether the Gas Utilities should have had additional fixed-price contracts, and if so, to determine the impact.⁴⁵²

275. By definition, buying at index ensures the price paid will reflect the market midpoint for that day. Buying at fixed price risks that the price paid could be higher or lower than the index. Although costs can be reduced by buying at fixed price, costs could also be exacerbated.⁴⁵³ Further, the Gas Utilities should not be expected to systematically beat the index by buying more gas at a fixed price.⁴⁵⁴

276. On February 12, 2021, Xcel purchased spot gas at index, as described in greater detail above.⁴⁵⁵ Shortly after 9:00 a.m. on February 12, Xcel made a fixed-price purchase of 15,000 Dth at a price of \$75/Dth.⁴⁵⁶

277. Xcel then made two intra-weekend spot gas purchases at a fixed price over Presidents' Day weekend.⁴⁵⁷ On February 13, 2021, Xcel purchased 14,000 Dth of gas for a fixed price of \$95.00/Dth.⁴⁵⁸ On February 15, 2021, Xcel purchased 8,280 Dth at a fixed price of \$157.00/Dth.⁴⁵⁹ The Department disputes the reasonableness of these purchases, as explained above, but its concerns are not related to the fixed-price aspect of these purchases.

278. Xcel purchased both index-priced and fixed-price gas on February 16. On the morning of February 16, Xcel decided to meet a portion of its supply needs for February 17 with fixed price gas after considering a number of factors: the weather forecast for the next few days ahead showed warming trends; Xcel was buying gas for just the day ahead (as opposed to its purchases for the long weekend that had to cover four days); and based on its experience, Xcel believed that lingering market fear would cause prices to start higher, then move lower as the trading cycle progressed.⁴⁶⁰

279. Xcel makes fixed-price purchases more regularly than the other utilities.⁴⁶¹ Based on its reasoning and experience, and in an attempt to capture anticipated lower costs, Xcel delayed a portion of its daily supply purchases as a limited hedge against the

⁴⁵² Order for Hearing at 22.

⁴⁵³ Ex. 506 at 75-76 (King Direct).

⁴⁵⁴ *Id.* at 76.

⁴⁵⁵ Ex. 207 at 13 (Green Direct).

⁴⁵⁶ *Id.* at 14-15 ("Shortly after 9 a.m., the Company made a fixed price purchase of 15,000 Dth at \$75 per Dth for Generation. This decision was made after I completed my index-based purchases for the morning. It was determined that Generation needed a little more gas supply for the weekend in case more gas-fired plants were dispatched by [MISO]. . . . Because the index-based market was no longer being offered at this time, I purchased gas using a fixed-price deal.").

⁴⁵⁷ *Id.* at 19.

⁴⁵⁸ *Id.*

⁴⁵⁹ *Id.*

⁴⁶⁰ Ex. 204 at 27 (Derryberry Rebuttal).

⁴⁶¹ Ex. 506 at 76 (King Direct).

early index market.⁴⁶² Prices did come down throughout the day's trading session.⁴⁶³ Xcel ultimately purchased approximately 50,000 Dth at fixed prices between \$9 and \$95 for a weighted average of \$28.50/Dth, compared to the weighted average of index-based purchases of \$132.26/Dth.⁴⁶⁴

280. No party to this proceeding asserts that Xcel should have purchased additional fixed-price gas. Xcel has established that it was prudent not to purchase additional fixed-price gas in connection with the February Event.

C. Conservation Efforts

281. The Order for Hearing directed that this Report address whether the Gas Utilities should have made more robust conservation efforts, and if so, to determine the impact.⁴⁶⁵

282. Natural gas utilities can address demand for natural gas by conservation, which lowers overall demand.⁴⁶⁶ At issue here, however, is whether the Gas Utilities should have made voluntary conservation pleas to seek reductions in demand.

283. A conservation plea is generally a request from the utility to customers to voluntarily reduce usage for a defined amount of time. These types of pleas are driven by a short-term event and distinguishable from general long-term efficiency and conservation measures.⁴⁶⁷ Conservation pleas have generally been limited to extraordinary circumstances and are used as a last-resort reliability tool.⁴⁶⁸

284. While estimating the impact of a conservation plea is possible, there could be significant deviation from the actual impact. This potential deviation could have exposed the Gas Utilities to system imbalance penalties or other operational issues.⁴⁶⁹

285. It was not unreasonable for the Gas Utilities not to reduce spot purchases by relying on a conservation plea. Estimating the volume of load reduction from a conservation plea had the potential for wide deviations. The Gas Utilities have rarely made a plea to firm customers and have generally only used this technique as an emergency measure.⁴⁷⁰

286. No party has challenged Xcel's actions on this issue. The record supports finding that Xcel acted prudently by not relying on a conservation plea to reduce demand in connection with the February Event.

⁴⁶² Ex. 204 at 27 (Derryberry Rebuttal).

⁴⁶³ *Id.*

⁴⁶⁴ *Id.* at 27-28.

⁴⁶⁵ Order for Hearing at 22.

⁴⁶⁶ Ex. 203 at Sch. 2 at 4 (Derryberry Direct); Ex. 211 at 18 (Krug Direct).

⁴⁶⁷ Ex. 506 at 101 (King Direct).

⁴⁶⁸ *Id.* at 103.

⁴⁶⁹ *Id.* at 102.

⁴⁷⁰ *Id.* at 103.

D. Third Party Recovery and Other Mitigation

287. The Commission directed that this proceeding address whether the Gas Utilities timely and appropriately pursued recovery through insurance, federal regulatory actions, market rules, contract enforcement, and other available legal actions such that they have not missed deadlines or become barred from possible recovery on behalf of ratepayers, and to determine the potential financial impact.⁴⁷¹

288. Following the February Event, Xcel took steps to mitigate the impact of the price spike on customers and to lessen the likelihood of a recurrence of such an event.⁴⁷² Xcel immediately engaging the Brattle Group to evaluate potential third-party actions and to gain further understanding of the factors that caused the price spikes during the February Event.⁴⁷³

289. Xcel obtained reimbursements from NNG of approximately \$790,000 and credited those to customers.⁴⁷⁴

290. Xcel worked to identify customers who failed to curtail and who would be assessed an additional \$50/Dth (\$100/Dth total penalty) for the second non-compliance incident, with any such penalties being credited to firm customers.⁴⁷⁵

291. Xcel proposed to extend recovery of the costs associated with the February Event, and has now extended that recovery to 63 months for residential customers, without carrying costs, and providing specific relief to Xcel's low-income customers.⁴⁷⁶ Xcel worked with stakeholders to develop these measures.⁴⁷⁷

292. Xcel engaged with state and federal legislators to pursue financial relief for customers through the use of American Rescue Plan dollars or other means and with FERC to explore potential market reforms.⁴⁷⁸ Xcel has also participated in discussions at FERC to explore potential market reforms.⁴⁷⁹

293. Xcel has explored potential changes to its gas planning and procurement strategies going forward.⁴⁸⁰

294. The Department proposes that the Commission delay a determination of prudence related to this issue, noting that FERC is investigating the February Event and the investigation will take time to unfold.⁴⁸¹ The Department contends that the

⁴⁷¹ Order for Hearing at 22-23.

⁴⁷² Xcel Ex. 211 at 28-33 (Krug Direct).

⁴⁷³ *Id.* at 28; Ex. 214 at Sch. 2 ¶¶2-3 (Levine Direct).

⁴⁷⁴ Ex. 211 at 32 (Krug Direct); Ex. 203 at 20 (Derryberry Direct).

⁴⁷⁵ Ex. 211 at 28 (Krug Direct).

⁴⁷⁶ Ex. 212 at 25-26 (Krug Rebuttal); Ex. 221 at 3 (Peterson Direct)

⁴⁷⁷ Ex. 211 at 29 (Krug Direct); Ex. 221 at 3 (Peterson Direct).

⁴⁷⁸ Ex. 211 at 29 (Krug Direct); Ex. 203 at 21 (Derryberry Direct).

⁴⁷⁹ Ex. 211 at 29 (Krug Direct); Ex. 203 at 21 (Derryberry Direct).

⁴⁸⁰ Ex. 211 at 29 (Krug Direct).

⁴⁸¹ Ex. 506 at 104 (King Direct).

Commission should withhold a prudency determination until further facts come to light, and potential remedies that could result from the investigations are better known. In the meantime, the Department recommends that the Gas Utilities should continue to report to the Commission on their ongoing efforts to ensure that ratepayers receive any potential recovery of funds recouped should investigations find evidence of market manipulation or other wrongdoing.⁴⁸²

295. There is no evidence that Xcel has failed to comply with the Commission's direction to pursue information and recovery from other sources, and Xcel has complied with the Commission's direction to make compliance filings regarding this issue. There is no basis at this time to find that Xcel has acted imprudently or that it should not be permitted to recover its extraordinary costs based on this issue. As such, the Commission should make an initial determination that Xcel has acted prudently, and then require Xcel to make ongoing compliance filings. The Commission may take further action as warranted in light of any further developments.

E. Assigning Costs of the February Event based on Consumption

296. Xcel does not have a complete billing quality data set for all individual customer usage during the five-day February Event.⁴⁸³

297. In order to assess daily usage for each customer, Xcel would have to rely on manual data manipulation and make assumptions for the more than 20,000 customers for which Xcel does not have daily meter read data.⁴⁸⁴

298. Creating an individual surcharge for each of Xcel's customers and developing processes for ensuring individual surcharges remained accurate would not be practical, and it could create customer confusion.⁴⁸⁵

299. The Department determined that customer usage going forward is a reasonable approximation of usage during the February Event and that the any potential incremental cost causation improvements would need to be balanced against other ratemaking goals such as having rates that are simple, understandable, and affordable.⁴⁸⁶

300. Direct assignment of gas costs incurred during the February Event is not necessary to ensure equitable recovery of prudently incurred costs. In apportioning revenue responsibility and designing rates, the Commission must balance competing principles and policies. As the Department determined, individual customer usage likely remains similar year-to-year and provides a reasonable approximation of use during the February Event. Given that using more accurate usage data is either impossible or would require the Gas Utilities to radically depart from typical billing practices, the Administrative

⁴⁸² See Department's Initial Br. at 81-82 (Mar. 15, 2022) (eDocket No. 20223-183839-05).

⁴⁸³ Ex. 221 at 8 (Peterson Direct).

⁴⁸⁴ *Id.*

⁴⁸⁵ *Id.* at 8-9.

⁴⁸⁶ Ex. 506 at 108 (King Direct).

Law Judges agree that the incremental benefits are outweighed by the impacts to other practical considerations and goals such as ensuring understandable rates for customers.

301. Xcel does have complete billing quality data for its interruptible customers.⁴⁸⁷

302. There are some interruptible customers who fully curtailed during the February Event and therefore used no gas during the February Event.⁴⁸⁸

303. Xcel proposed to exempt interruptible customers who fully interrupted and used no gas from the February Event surcharge, and to assign the amounts to the remaining customers in the interruptible class.⁴⁸⁹ No party opposed this proposal.

304. Commercial and industrial customers have the option to move from natural gas sales service to transportation service.⁴⁹⁰ Transportation service customers contract for gas supplies separate from the Company's system supply, and do not pay the Company's PGA rates or PGA true-up.⁴⁹¹ Commercial and industrial customers have an incentive to move to transportation service in an attempt to avoid paying the February Event surcharge.⁴⁹² If customers are allowed to move to transportation service without paying their portion of the surcharge, it would result in a larger remaining balance for other customers.⁴⁹³

305. Xcel proposed to track customers who received natural gas sales service in February 2021 who then subsequently move to transportation service during the period of time the surcharge is collected so that these customers can be charged an exit fee the remaining months the surcharge is being collected.⁴⁹⁴ No party has opposed this proposal.

306. It is not reasonable to assign costs to most customers based on consumption during the February Event. However, Xcel should assign amounts to interruptible customers who used gas during the February Event, and should track customers who switch to transportation service to recover the appropriate costs during the recovery period.

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

⁴⁸⁷ See Ex. 221 at 9 (Peterson Direct).

⁴⁸⁸ *Id.*

⁴⁸⁹ *Id.*

⁴⁹⁰ *Id.* at 10.

⁴⁹¹ *Id.*

⁴⁹² *Id.*

⁴⁹³ *Id.*

⁴⁹⁴ *Id.*

CONCLUSIONS OF LAW

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

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

3. Every rate made, demanded, or received by any public utility must be just and reasonable.⁴⁹⁵

4. The burden to prove that its actions were prudent and that recovery of extraordinary costs is reasonable rests on Xcel.⁴⁹⁶

5. Utilities do not enjoy a presumption of prudence.⁴⁹⁷ Doubts as to reasonableness are resolved in favor of the consumer.⁴⁹⁸

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

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

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

RECOMMENDATION

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

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

⁴⁹⁵ Minn. Stat. § 216B.03.

⁴⁹⁶ Minn. Stat. § 216B.16, subd. 4.

⁴⁹⁷ *In re a Comm'n Investigation into Xcel Energy's Monticello Life-Cycle Management/Extender Power Uprate Project*, MPUC Docket No. E-002/CI-13-754, Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes (May 8, 2015).

⁴⁹⁸ Minn. Stat. § 216B.03; *see also* Order for Hearing at 3 ("In incurring costs necessary to provide service, utilities are expected to act prudently to protect ratepayers from unreasonable risks.").

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

Dated: May 24, 2022


JESSICA A. PALMER-DENIG
Administrative Law Judge


BARBARA J. CASE
Administrative Law Judge

NOTICE

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

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

May 24, 2022

See Attached Service List

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

***In the Matter of a Petition of Northern States Power Company d/b/a
Xcel Energy to Recover February 2021 Natural Gas Costs***

**OAH 71-2500-37763
MPUC G-002/CI-21-610**

To All Persons on the Attached Service List:

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

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

Sincerely,



MICHELLE SEVERSON
Legal Assistant

Enclosure

cc: Docket Coordinator

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

CERTIFICATE OF SERVICE

<p>In the Matter of the Petitions for Recovery of Certain Gas Costs</p> <p>In the Matter of a Petition of Northern States Power Company d/b/a Xcel Energy to Recover February 2021 Natural Gas Costs</p>	<p>OAH Docket No.: 71-2500-37763 MPUC G-002/CI-21-610</p>
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Michelle Severson certifies that on May 24, 2022, she served the true and correct

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION by

eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

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