

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 the Petition of Minnesota
Energy Resources Corporation for
Approval of a Recovery Process for Cost
Impacts Due to February Extreme Gas
Market Conditions

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 9

 V. General Background Regarding the February Event 14

 VI. Background Regarding MERC..... 14

 VII. When and to What Extent the Gas Utilities Became Aware of
 Potential for Extreme Weather During the February Event..... 18

 VIII. MERC’s Actions Before the February Event 24

 A. Overview of MERC’s Gas Procurement Planning 24

 B. MERC’s Gas Procurement Before the February Event 28

 1. Customer Demand and Design Day Planning..... 28

 a. Interstate Pipeline Transportation Capacity 29

 b. Baseload Gas Purchases 30

 c. Geographic Diversity of Supply..... 31

d.	Swing Supply/Call Options for Gas.....	32
e.	Daily Gas Purchases	32
C.	Disputed Issue Related to MERC’s Planning: Use of Hedging Instruments	33
1.	Overview of Hedging	33
2.	Prudency of MERC’s Use of Hedging Tools.....	35
IX.	MERC’s Actions During the February Event.....	41
A.	General Timeline of MERC’s Actions Leading Up to and During the February Event	41
B.	MERC Reliably Served Gas Customers During the February Event.....	44
C.	Disputed Issues Related to Load Forecasting and Curtailments During the February Event.....	46
1.	MERC’s Load Forecasting and Supply Reserve Margin During the February Event	47
2.	Curtailment During the February Event	57
D.	MERC’s Usage of Storage During the February Event	62
1.	Overview of Storage Contracts and Planning.....	62
2.	Use of Storage Capacity During the February Event.....	64
X.	Additional Undisputed Issues.....	66
A.	MERC’s Conservation Messaging.....	66
B.	MERC’s Use of Daily Index Priced Versus Fixed-Price Natural Gas Supply During the February Event.....	67
C.	Post February Event Actions.....	68
D.	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?	70
	CONCLUSIONS OF LAW	72
	RECOMMENDATION	72
	NOTICE.....	73

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

In the Matter of the Petition of Minnesota
Energy Resources Corporation for
Approval of a Recovery Process for Cost
Impacts Due to February Extreme Gas
Market Conditions

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 Minnesota Energy Resources Corporation (MERC) 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.

Elizabeth M. Brama and Kristin M. Stastny, Taft Stettinius & Hollister, LLP, and Catherine A. Phillips of MERC, appeared on behalf of MERC.

¹ In addition to MERC, the "Gas Utilities" include CenterPoint Energy (CenterPoint Energy), Northern States Power Company d/b/a Xcel Energy (Xcel), 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. 20218-177548-02) (Order for Hearing).

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

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

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

Andrew P. Moratzka and Riley A. Conlin, Stoel Rives LLP, appeared on behalf of the Super Large Gas Intervenors (SLGI).

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

STATEMENT OF THE ISSUES

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

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

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

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

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

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

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

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

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

³ *Id.* at 7-8.

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?

SUMMARY OF RECOMMENDATION

The ALJs conclude that MERC acted prudently in connection with the February Event, that the extraordinary gas costs MERC 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 unprecedented levels of under-recovered costs for the purchase of natural gas in order to do so.

5. The Gas Utilities, including MERC, 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 its Order for Hearing, which, among other things, referred these matters to the Office of Administrative Hearings (OAH) for contested case proceedings.⁴

7. The Commission identified the parties to the contested case proceeding as CenterPoint, Xcel Energy, 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

⁴ Order for Hearing at 7.

⁵ See First Prehearing Order at 3 (Sept. 20, 2021) (eDocket No. 20219-178082-03).

⁶ *Id.*

⁷ *Id.*

Event	Date
Post-Hearing Reply Briefs and Revised Findings Submitted by All Parties (All Parties to Submit Redlines of Proposed Findings)	March 25, 2022
ALJ Report Issued	May 24, 2022
Arguments and Exceptions	June 3, 2022 ⁸

10. On October 1, 2021, CUB petitioned to intervene as a party.⁹ The ALJ's 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. G-008/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. G-008/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

⁸ *Id.* at 4.

⁹ Petition to Intervene by The Citizens Utility Board of Minnesota (Oct. 1, 2021) (eDocket No. 202110-178489-03).

¹⁰ Order Granting Petition to Intervene by The Citizens Utility Board of Minnesota (Oct. 12, 2021) (eDocket No. 202110-178734-02).

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. 202110-178978-04) (To the extent that Minneapolis's filings could be construed as a request to intervene in the remaining three dockets, Minneapolis's Petition to Intervene was denied).

¹⁵ Protective Order (Oct. 8, 2021) (eDocket No. 202110-178630-04).

¹⁶ Protective Order for Highly-Confidential Trade Secret Data (Oct. 11, 2021) (eDocket No. 202110-178678-04); Amended Highly Confidential Trade Secret Protective Order (Oct. 26, 2021) (eDocket No. 202110-179189-02).

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

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

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

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

18. The ALJ's 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 Joint Gas Utilities, CenterPoint Energy, Great Plains, Xcel Energy, MERC, the Department, CUB, and the OAG filed Written Summaries of Pre-Filed Testimony.

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

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.

¹⁷ Request for the OAH to Hold Public Hearings (Jan. 27, 2022) (eDocket No. 20221-182049-02).

¹⁸ Notice of Prehearing Conference (Jan. 31, 2022) (eDocket No. 20221-182273-03).

¹⁹ Second Prehearing Order (Feb. 7, 2022) (eDocket No. 20222-182513-02).

²⁰ Notice of Virtual Public Hearings (Feb. 4, 2022) (eDocket No. 20222-182412-03).

²¹ Addition to Notice of Virtual Public Hearings (Feb. 14, 2022) (eDocket No. 20222-182753-02).

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

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 MERC 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 contours 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

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.

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 only 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. 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

31. A determination of prudence must recognize that a utility may take a range of actions or decisions that are prudent.³¹ In most instances, there will not be one singular prudent action or decision but rather, a range of actions that are reasonable and prudent.³² A prudence review is focused on an examination of a utility's specific decisions and whether the decisions were prudent or imprudent.³³

32. The burden to prove that its actions were prudent, and that recovery of extraordinary costs is reasonable, rests on MERC.³⁴

33. Utilities do not enjoy a presumption of prudence.³⁵ Doubts as to reasonableness are resolved in favor of the consumer.³⁶

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

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. 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.").

³⁴ Minn. Stat. § 216B.16, subd. 4 (2020).

³⁵ *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).

³⁶ 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.").

IV. Overview of U.S. Natural Gas Markets

34. 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.³⁷ 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.³⁸ In contrast, the natural gas industry consists of multiple entities operating independently.³⁹ 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.⁴⁰

35. 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.⁴¹

36. In 1993, Federal Energy Regulatory Commission (FERC) implemented Order No. 636.⁴² Order No. 636 “unbundled” different aspects natural gas industry.⁴³ 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.⁴⁴

37. 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.⁴⁵ Natural gas is not produced within Minnesota, so the Gas Utilities rely on interstate

³⁷ Ex. 100 at 3, 15-16 (Smead Direct).

³⁸ *Id.* at 3, 15-16.

³⁹ *Id.* at 3-4.

⁴⁰ *Id.* at 16.

⁴¹ *Id.* at 3-4; *see also* Ex. 506 at 3-4 (King Direct).

⁴² Ex. 100 at 4 (Smead Direct).

⁴³ *Id.*

⁴⁴ *Id.*; *see also* Ex. 506 at 5 (King Direct).

⁴⁵ Ex. 506 at 6 (King Direct).

pipelines to transport gas produced in other states to Minnesota.⁴⁶ Second, the LDC also contracts with suppliers of physical natural gas.⁴⁷

38. 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.⁴⁸ Natural gas prices “are driven by the competitive market forces of supply and demand.”⁴⁹

39. 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.⁵⁰

40. 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).⁵¹

41. 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.⁵²

42. The physical delivery of gas from a seller to a buyer is based on three primary structures: (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));⁵³ (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-

⁴⁶ *Id.* at 7.

⁴⁷ *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).

⁴⁸ *Id.* at 7; Ex. 506 at 5-6 (King Direct).

⁴⁹ Ex. 506 at 5 (King Direct).

⁵⁰ Ex. 100 at 20-23 (Smead Direct).

⁵¹ *Id.* at 7; *see also* Ex. 506 at 24 (King Direct).

⁵² Ex. 100 at 5-6 (Smead Direct); *see also* Ex. 506 at 6-7 (King Direct).

⁵³ Ex. 100 at 11, 14 (Smead Direct).

year deals.⁵⁴ All of these different types of deals can be based on a fixed price or indexed based on a price reporting agency (PRA)⁵⁵ index.⁵⁶

43. Monthly transactions are for delivery of specified volumes, effective on the first of the month (and thus called “FOM”) and remain in effect each day of the upcoming month.⁵⁷ 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.⁵⁸ For February 2021 FOM deals, trading closed on January 28, 2021.⁵⁹

44. 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.⁶⁰ The intra-weekend market represents a less liquid bilateral market without the benefits of regular business day trading.⁶¹

45. 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.⁶² 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).⁶³ 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).⁶⁴

46. 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.⁶⁵ Index deals are the dominant pricing structure, since neither counterparty is making a wager on the difference between the contract price and a changing market during the duration of the agreement.⁶⁶

⁵⁴ *Id.* at 11.

⁵⁵ 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.

⁵⁶ *Id.* at 12.

⁵⁷ *Id.* at 14.

⁵⁸ *Id.* at 14-15.

⁵⁹ Evidentiary Hearing Tr. Vol. 2C at 26-27 (King).

⁶⁰ Ex. 100 at 18 (Smead Direct).

⁶¹ Ex. 506 at 24-25 (King Direct).

⁶² Ex. 100 at 7 (Smead Direct).

⁶³ *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.”)

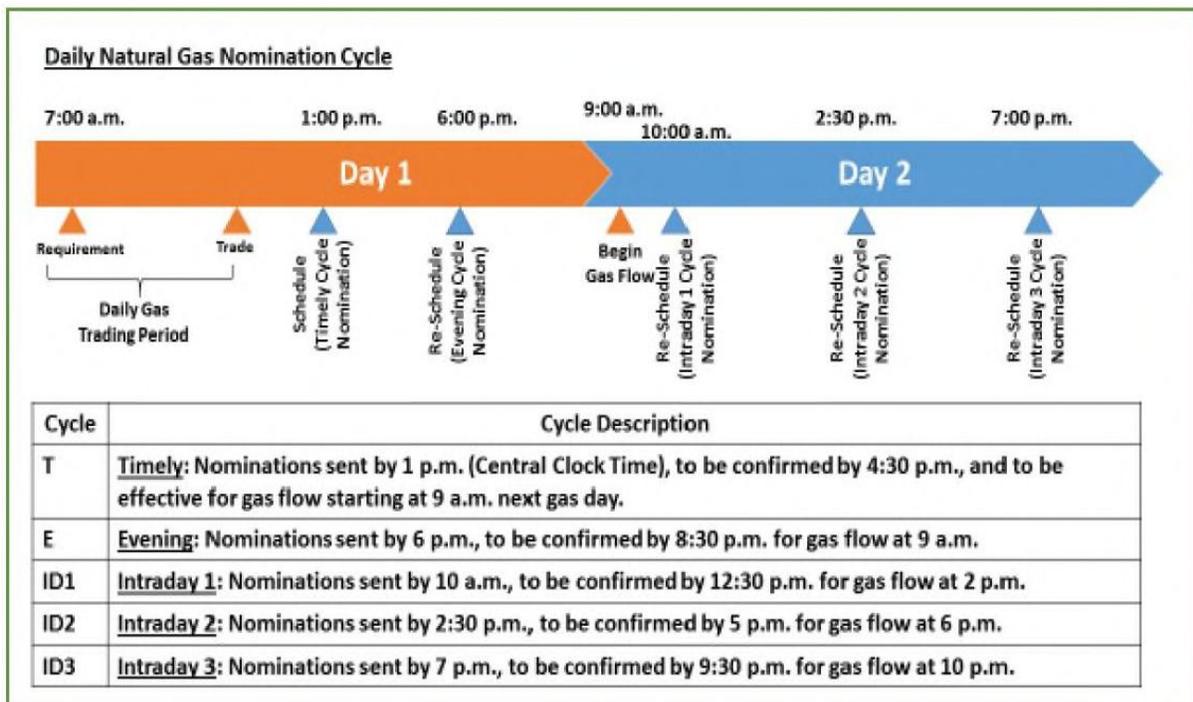
⁶⁴ Ex. 100 at 14 (Smead Direct).

⁶⁵ *Id.* at 7-8.

⁶⁶ *Id.* at 12.

47. Once physical natural gas is purchased, it needs to be scheduled (or nominated) to flow on the transportation pipelines. FERC requires transportation pipelines to incorporate nomination standards developed by the North American Energy Standards Board (NAESB) into their tariffs.⁶⁷ These standards set five different cycles upon which natural gas can be nominated—two prior to the Gas Day (i.e., the period of twenty-four consecutive hours beginning and ending at 9:00 a.m. Central Time) and three opportunities during the Gas Day.⁶⁸ 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.⁶⁹

NAESB Timeline⁷⁰



48. 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, for being out of balance between receipts and deliveries.⁷¹ Those penalties can be up to three times the applicable daily spot price per unit on that day.⁷²

⁶⁷ *Id.* at 16.

⁶⁸ *Id.* at 16-17.

⁶⁹ *Id.* at 16.

⁷⁰ Ex. 506 at 24, Figure 10 (King Direct).

⁷¹ Ex. 100 at 18 (Smead Direct).

⁷² *Id.* at 24.

49. 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.⁷³

50. The physical gas supply options available to the Gas Utilities are: (1) baseload purchases; (2) storage assets; (3) swing supply; and (4) daily spot purchases.⁷⁴

51. Baseload purchases refer to a fixed volumes of gas that flow every day for the term of the contract.⁷⁵ Baseload contracts are either monthly contracts or long-term contracts (more than one month).⁷⁶ Typically, these baseload purchases are priced at FOM index price or a fixed price.⁷⁷

52. 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.⁷⁸ Storage supplies are filled during the lower demand summer season for use during the higher demand winter season.⁷⁹ 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.⁸⁰ Because regional storage around Minnesota is fully subscribed, the Gas Utilities cannot readily acquire additional storage without considerable effort and investment.⁸¹

53. 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.⁸² Swing supply provides assurance in advance that a quantity of physical gas supply will be available.⁸³ Although swing supply provides quantity certainty, those deals are typically priced at a daily spot index.⁸⁴

54. 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).⁸⁵ Daily spot purchases can be

⁷³ *Id.* at 24-25.

⁷⁴ *Id.* at 31.

⁷⁵ Ex. 506 at 21 (King Direct).

⁷⁶ *Id.*

⁷⁷ *Id.*

⁷⁸ *Id.*

⁷⁹ *Id.*

⁸⁰ *Id.*

⁸¹ *Id.* at 21-22.

⁸² *Id.* at 20.

⁸³ *Id.*

⁸⁴ *Id.*

⁸⁵ Ex. 100 at 11, 14 (Smead Direct).

purchased for a negotiated fixed price or pricing can be based on the published daily market price index.⁸⁶

V. General Background Regarding the February Event

55. In February 2021, cold weather across much of the United States led to increased demand for natural gas and, in some areas, supply disruptions. On February 12, 2021, an unprecedented and unforeseen rise in natural gas spot market prices ensued, including in Minnesota. MERC maintained continuous service to each of its 243,000 customers during this period, but incurred high levels of under-recovered costs purchasing gas on the spot market to provide that reliable gas supply.⁸⁷

56. The large geographic scale of the cold weather led to large increases in the demand for natural gas. Freeze-offs⁸⁸ in production areas led to an abrupt and unexpected reduction in supply, just as demand across much of the U.S. spiked due to colder-than-normal temperatures.⁸⁹

57. The Midwest, including Minnesota, did not have any physical issues getting gas, and MERC did not experience any operational issues delivering gas to MERC's customers during the February Event.⁹⁰ Although it was cold, it was not near the design day conditions⁹¹ that MERC plans for and has previously experienced, and operates its system and manages its assets to meet.⁹² Rather, the February Event was an economic market event, which resulted in unpredictable and unprecedented prices in the daily gas spot market.⁹³

58. Based on the Commission's definition of extraordinary gas costs as costs incurred during the February Event, from February 13-17, 2021, and the margin between \$20/Dekatherm (Dth) and the actual average daily price, MERC incurred extraordinary gas costs of \$64,975,882 associated with the February Event.⁹⁴

VI. Background Regarding MERC

59. MERC is a gas distribution public utility and is a subsidiary of WEC Energy Group, Inc. (WEC). MERC provides natural gas service to approximately 243,000

⁸⁶ *Id.* at 12.

⁸⁷ Ex. 400 at 7 (Eidukas Direct).

⁸⁸ Freeze offs occur when temperatures fall below freezing, resulting in water and other liquids contained in the natural gas mixture to freeze, blocking the flow of gas out of the wellhead. *Id.* at 8 n. 2.

⁸⁹ *Id.* at 8.

⁹⁰ *Id.*

⁹¹ A design day is a 24-hour period of natural gas demand that is used as the basis for planning capacity requirements. Design day conditions reflect the coldest weather expected to occur based on historic weather events. Ex. 403 at 19 (Mead Direct).

⁹² Ex. 400 at 8-9 (Eidukas Direct). On an Adjusted Heating Degree Day (AHDD) basis, which takes into account temperatures as well as the impacts of wind, the coldest weather on record at the weather stations used to plan for MERC's service areas took place in 2019 in the case of Bemidji, Cloquet, Minneapolis, Rochester, Worthington, and Ortonville and in 1996 for Fargo and International Falls. *Id.* at 9 n. 3.

⁹³ *Id.* at 9.

⁹⁴ Order for Hearing at 20.

customers in 52 counties and 179 communities throughout Minnesota, including Rochester, Rosemount, Fairmount, Appleton, Roseau, Cloquet, Silver Bay, and International Falls.⁹⁵

60. To provide natural gas service to customers in the communities MERC serves, MERC must plan for and secure adequate interstate pipeline capacity (i.e., transportation on the interstate pipeline) to allow for the delivery of natural gas supplies from the areas where natural gas is produced to interconnection points on MERC's distribution system (receipt points). MERC must also contract for natural gas supplies to meet customer demand. Those gas supplies are delivered through the appropriate interstate pipeline(s) to the interconnections with MERC's distribution system, which delivers the natural gas to MERC's customers for use in their homes and businesses.⁹⁶

61. Because it serves large and geographically diverse areas in Minnesota, MERC relies on four separate interstate pipelines to serve its customers in their various communities:

(1) Centra Pipeline (Centra) runs from Spruce Manitoba, Canada, into Minnesota from Warroad to Baudette. Centra is used to serve communities in Northern Minnesota.

(2) Viking Gas Transmission Pipeline (Viking) runs from Emerson (TransCanada) on the U.S. side to serve MERC's customers from Ada to Camp Ripley.

(3) Great Lakes Transmission Pipeline (Great Lakes) runs from Emerson (TransCanada) on the U.S. side to serve MERC's customers from Thief River Falls to Cloquet.

(4) Northern Natural Gas (NNG or Northern) Pipeline runs from Ventura in Iowa and Demarcation (Demarc) (near Clifton, Kansas), which is the transfer point for gas coming north from NNG's Field area to NNG's Market area, to serve MERC's customers in Southern Minnesota.⁹⁷

62. MERC is divided into two distinct Purchased Gas Adjustment (PGA) areas, which are referred to as purchased gas adjustment areas (PGA Areas):

(1) MERC-Consolidated, which is served by Centra, Viking, and Great Lakes (the Consolidated pipelines); and

(2) MERC-NNG, which is served by NNG Pipeline.⁹⁸

⁹⁵ *Id.* at 1, 3-4; Ex. 404 at Sch. 1 (Mead Direct Schedules) (map of areas MERC serves).

⁹⁶ Ex. 400 at 5 (Eidukas Direct).

⁹⁷ *Id.* at 5-6; see also Ex. 408 at 6-7 (Sexton Direct).

⁹⁸ Ex. 400 at 6 (Eidukas Direct); Ex. 403 at 9-10 (Mead Direct); Ex. 408 at 6-7 (Sexton Direct).

63. Because these PGA areas are geographically separate, they do not share pipeline capacity, storage, or natural gas supplies.⁹⁹ In most cases, MERC's customers are served solely by a specific pipeline, with very few exceptions.¹⁰⁰

64. MERC holds firm natural gas transportation capacity on the Centra, Viking, and Great Lakes pipeline systems to serve its customers in the Consolidated PGA area. Natural gas supplies are acquired at Emerson and Spruce, Manitoba and transported on Viking, Great Lakes, and Centra to MERC's Consolidated PGA area markets directly connected to those pipelines.¹⁰¹

65. MERC did not incur any extraordinary costs during the February Event within its MERC-Consolidated PGA area market. During the February Event, natural gas market prices at Emerson, Manitoba and Spruce, Manitoba did not experience price spikes to the level that resulted in extraordinary costs.¹⁰²

66. During the February Event, MERC-NNG had 195,556 Dth/day of firm pipeline transportation capacity on the NNG pipeline system from various receipt points to MERC-NNG PGA area markets.¹⁰³

67. Upstream of Northern, MERC-NNG also holds a contract for 50,000 Dth/day of firm pipeline transportation capacity on the Northern Border Pipeline (Northern Border) system from Port of Morgan, Montana to an interconnect with Northern at Ventura, Iowa.¹⁰⁴

68. During the 2020-2021 winter season, MERC had four upstream natural gas sources to supply its firm capacity on Northern, for ultimate delivery to customers on the MERC-NNG PGA area markets. The four sources were:

(1) Northern pipeline interconnects with Great Lakes at Carlton and Grand Rapids, Minnesota.

(2) Northern's Field to Market Demarcation point (Demarc).

(3) Northern pipeline interconnects with Northern Border at Ventura, Iowa; Welcome, Minnesota; Marshall, South Dakota; and Aberdeen, South Dakota.

(4) Physical receipt points along the Northern Border pipeline system from the US/Canadian border import point at Port of Morgan, Montana to Ventura, Iowa into MERC-NNG's firm capacity on Northern Border, which then flowed from

⁹⁹ Ex. 400 at 6 (Eidukas Direct).

¹⁰⁰ Ex. 403 at 10 (Mead Direct).

¹⁰¹ Ex. 408 at 7-8 (Sexton Direct).

¹⁰² *Id.* at 8-9.

¹⁰³ *Id.* at 10.

¹⁰⁴ *Id.*

Northern Border into Northern at MERC's available receipt point capacity at Northern's Demarc interconnects with Northern Border.¹⁰⁵

69. The table below provides a summary of the MERC-NNG firm primary receipt point maximum daily quantity (MDQ) rights into its Northern firm transportation capacity during the February event.¹⁰⁶

**MERC-NNG Firm Receipt Point Capacity into Northern During February Event
(Dth/day)**

Receipt Point Location	Firm Receipt Point MDQ
Northern Border Interconnects	
Ventura, Iowa	95,651
Welcome, Minnesota	9,004
Marshall, South Dakota	12,000
Aberdeen, South Dakota	5,558
Total Northern Border Interconnects	122,213
Northern Demarc	42,371
Great Lakes Interconnects	
Carlton, Minnesota	24,972
Grand Rapids, Minnesota	6,000
Total Great Lakes Interconnects	30,972
Total Firm Receipt Point Capacity	195,556

Note: MERC-NNG also retained 10,000 Dth/day of capacity on Northern Border that was available to deliver into the Northern system.

70. MERC's contracted pipeline capacity cannot serve the two PGA systems interchangeably. Contracts for the pipeline capacity specifically state a primary receipt point (origination location) and a primary delivery point (destination location) dictating the firmness and primary path of the capacity. On colder days, MERC nominates all gas supply on the pipeline capacity to the firm primary delivery point specified on the contract with the pipeline.¹⁰⁷

¹⁰⁵ *Id.* at 11-12.

¹⁰⁶ *Id.* at 12; see also *id.* at Sch. 4 (Schedule 4 is a map showing the location of these receipt points).

¹⁰⁷ Ex. 403 at 11 (Mead Direct).

VII. When and to What Extent the Gas Utilities Became Aware of Potential for Extreme Weather During the February Event

71. The Commission’s Order for Hearing directed that this Report address the issue of when and to what extent the Gas Utilities became aware of the potential for extreme weather during the February Event, and whether they responded prudently and reasonably.¹⁰⁸

72. MERC first became aware of the potential for cold weather in its service territory approximately 10 days prior to the event. Several days later, MERC became aware that widespread cold weather could impact much of the United States.¹⁰⁹

73. In January 2021, the weather forecasts for February 2021 indicated that temperatures in Minnesota would be warmer than normal, as January 2021 had been.¹¹⁰

74. On January 31, 2021, the revised weather forecast indicated that Minnesota and the rest of the Upper Midwest would be colder than normal in the month of February but that temperatures would be normal or above normal in the south and south-central United States.¹¹¹ As of late January, the Gas Utilities expected that while demand for gas in Minnesota may be higher in February 2021, there was no indication that weather conditions would impact Minnesota’s gas supplies from the southern United States.¹¹²

75. Although February’s temperatures ultimately were very cold, the temperatures did not reach the peak conditions that MERC plans for, and that it operates its system and manages its assets, including storage assets, to meet.¹¹³

76. As shown in the table below, while February 14, 2021, was the coldest day during the February Event, the AHDDs were still well below MERC’s planning level based on historic experience.¹¹⁴

Comparison of MERC Design Day Versus Actual Weather During the February Event

MERC Design Day Criteria			Daily AHDD65 February 2021									
Weather Station	Date	AHDD65	2/10	2/11	2/12	2/13	2/14	2/15	2/16	2/17	2/18	
Bemidji	2/1/1996	107	87	87	91	94	92	83	77	70	70	
Cloquet	2/2/1996	103	84	81	91	89	90	83	74	59	59	
Fargo	1/18/1996	109	82	85	82	92	85	80	73	68	59	
International Falls	2/1/1996	107	87	86	90	91	93	84	79	71	66	
Minneapolis	2/2/1996	97	72	76	78	83	82	76	64	61	57	
Ortonville	1/14/2009	95	75	81	79	87	85	81	74	63	61	
Rochester	2/2/1996	101	74	79	83	86	88	83	69	64	62	
Worthington	1/18/1996	103	68	80	76	83	87	82	72	65	62	

¹⁰⁸ Order for Hearing at 22.

¹⁰⁹ Ex. 400 at 24 (Eidukas Direct).

¹¹⁰ Ex. 100 at 41-42 (Smead Direct).

¹¹¹ *Id.* at 42-43.

¹¹² *Id.* at 42.

¹¹³ Ex. 400 at 24-25 (Eidukas Direct); Ex. 403 at 42 (Mead Direct).

¹¹⁴ Ex. 400 at 25 (Eidukas Direct).

77. The energy industry became aware of the potential for extreme weather at some point in early February,¹¹⁵ but the extent of the extreme weather was not known at that time.¹¹⁶ The weather situation leading to the February Event continued to change and develop.¹¹⁷

78. On Thursday, February 4, 2021, NNG first called a system overrun limitation (SOL) and continued to call SOLs daily through February 17.¹¹⁸ When a SOL is in effect, 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.¹¹⁹

79. On Friday, February 5, 2021, the weekend before the February Event, Minnesota started to experience colder than normal temperatures.¹²⁰

80. 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.¹²¹

81. 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, 2021.¹²²

82. 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.¹²³ 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.¹²⁴ Notably, the February 12 forecast for Texas projected a shorter duration of cold weather and warmer temperatures than actually occurred.¹²⁵

83. Going into the February Event, MERC could not have reasonably predicted that the gas prices in February 2021 would reach the levels they did.¹²⁶ While previous cold weather events with similar temperatures have occurred in Minnesota, those events

¹¹⁵ Ex. 506 at 51 (King Direct).

¹¹⁶ *Id.* at 53.

¹¹⁷ *Id.*

¹¹⁸ Ex. 801 at 15 (Cebulko Direct); Ex. 403 at 44 (Mead Direct).

¹¹⁹ Ex. 801 at 15 (Cebulko Direct); Ex. 403 at 44-45 (Mead Direct).

¹²⁰ Ex. 801 at 14 (Cebulko Direct).

¹²¹ *Id.*

¹²² Ex. 100 at 42 (Smead Direct).

¹²³ Ex. 506 at 53 (King Direct).

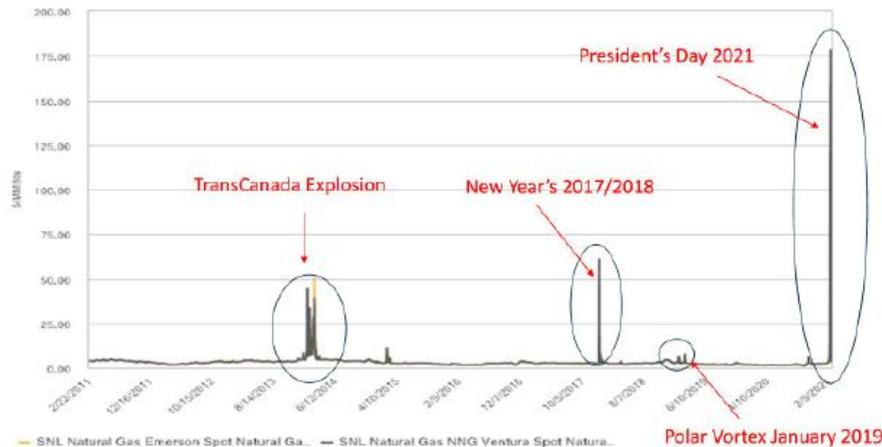
¹²⁴ *Id.*

¹²⁵ *Id.*

¹²⁶ Ex. 400 at 23 (Eidukas Direct); Ex. 403 at 42 (Mead Direct); Ex. 101 at 33 (Smead Rebuttal) ("A totally unprecedented price spike of monumental size occurred for a few days in February for reasons predominately related to the Texas and Oklahoma energy market that have been well examined in retrospect, but could not have been fully anticipated by Minnesota gas utilities.").

did not result in similar, unprecedented market price spikes.¹²⁷ The following figure highlights previous gas spot prices following the TransCanada explosion and previous polar vortex winter events.¹²⁸

10-Year Historical Gas Spot Prices



84. With regard to previous price spikes, the table below lists the cold weather events that were as cold, or colder, than February 2021, and the prices associated with those events at Ventura and Demarc.¹²⁹

Historic Cold Weather Events and Prices

Similar Cold Weather Incidents			
Weather Event Period (Year/Mo)	HDD Range ^{1/}	Max Vent \$/Dth during Period	Max Demarc \$/Dth during Period
Feb-21	77-85	\$ 154.91	\$ 231.67
Feb-20	77	\$ 2.07	\$ 2.07
Mar-19	79	\$ 8.96	\$ 8.48
Feb-19	77	\$ 3.57	\$ 3.43
Jan-19	77-99	\$ 6.74	\$ 4.23
Dec-17	80-85	\$ 67.46	\$ 3.50
Dec-16	78-81	\$ 4.07	\$ 4.07
Jan-16	82-83	\$ 2.65	\$ 2.65
Feb-15	79	\$ 7.06	\$ 6.81
Jan-15	80	\$ 3.72	\$ 3.69
Mar-14	82	\$ 41.58	\$ 19.14
Jan-14	79-84	\$ 53.31	\$ 6.22
Jan-14	91	\$ 9.61	\$ 6.38

^{1/} Heating Degree Days (HDD) value represents the day's average temperature that is below 65 Fahrenheit, including the wind factor.

¹²⁷ Ex. 400 at 21 (Eidukas Direct).

¹²⁸ *Id.* at 22-23.

¹²⁹ Ex. 403 at 43 (Mead Direct).

85. The following table identifies all the periods since 2014 in which the prices went over \$20/Dth at either Ventura or Demarc along with a brief explanation of the event.¹³⁰

Historic Daily Price Increases

Time Period	\$/Dth Ventura	\$/Dth Demarc	Additional Information
February 2021	\$188-\$7	\$232-\$15	February Market Event
December 2017	\$67	\$3.50	Cold weather event
March 2014	\$41-\$10	\$19-\$9	Waves of polar vortex fronts beginning Dec. 2013
February 2014	\$43-\$10	\$35-\$10	Waves of polar vortex fronts beginning Dec. 2013
January 2014	\$41-\$10	\$6.21	Waves of polar vortex fronts beginning Dec. 2013

86. The price spike event that immediately preceded the February Event occurred over the New Year holiday weekend in 2017-18, and caused Ventura to spike to the then record high level of about \$65/Dth for the three-day delivery period of December 29-31 (2017-18 New Year Event).¹³¹

87. 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.¹³²

88. 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.¹³³

89. Historically, the highest prices for gas supply on NNG was under \$70, so when the February Event began, any price offered above that was outside of the range of where a reasonable actor would or could have expected prices to settle.¹³⁴

¹³⁰ *Id.* at 44.

¹³¹ Ex. 506 at 15 (King Direct).

¹³² *Id.*

¹³³ *Id.* at 11, 17.

¹³⁴ Ex. 403 at 41-42 (Mead Direct).

90. While prices on February 10 and 11 were above average, at \$6.605/Dth to \$15.68/Dth, these prices were still well within the range of historic experience.¹³⁵

91. Daily index prices at the end of the day on February 11 for gas day February 12 settled at \$15.68/Dth at Northern-Demarc and \$15.42/Dth at Northern-Ventura.¹³⁶

92. As noted by the Department, “a reasonable actor” would have understood that 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 with those outcomes.”¹³⁷

93. MERC did not become aware of the price spike that occurred during the February Event until after MERC completed its purchase of daily supply on February 12. Late on the morning and through the afternoon of February 12, fixed price trades reached unprecedented price levels, but the final index prices were not known until prices were published on the evening of February 12.¹³⁸

94. The Department 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.”¹³⁹

95. CUB contends that MERC should have known about spiking gas prices prior to February 12, when prices in the spot market were in the 98th percentile at Emerson, Demarc, and Ventura compared to the previous five years. CUB argues that gas prices were significantly higher than average in Minnesota heading into the February Event, and these prices “should have caught the attention of all the utilities especially considering awareness of tightened supply conditions and deliverability concerns due to the pipeline warnings.” CUB also maintains that MERC did not acknowledge available information on February 16 when planning for gas day February 17.¹⁴⁰

96. However, CUB’s witness, Mr. Cebulko, agreed that the \$14 spot market price at Demarc on February 11 was less than a one percent increase over three previous price spikes during the previous 10 years, and so was consistent with prices previously seen by the Gas Utilities during those events.¹⁴¹

¹³⁵ Ex. 401 at 35 (Eidukas Rebuttal).

¹³⁶ Ex. 203 at Sch. 2 at 23 (Derryberry Direct); Ex. 403 at 47 (Mead Direct); Ex. 133 at 75-76 (Reed Direct).

¹³⁷ Ex. 506 at 60 (King Direct).

¹³⁸ Ex. 400 at 26 (Eidukas Direct).

¹³⁹ Ex. 506 at 59 (King Direct).

¹⁴⁰ Ex. 801 at 27-28 (Cebulko Direct).

¹⁴¹ Evidentiary Hearing Tr. Vol. 3 at 69-71 (Cebulko). It should also be noted that the Commission has determined that prices under \$20/Dth can be considered normal when it set the parameters for determining recovery of extraordinary costs. Order for Hearing at 11-12.

97. MERC disagrees that that tightening gas supply and rising prices heading into the February Event meant that an unprecedented price spike would occur. MERC notes Mr. Cebulko's assertions are in conflict with those of the Department's witness Mr. King.¹⁴² The OAG agreed that price spike that occurred during the February Event, could not have been predicted, though, as noted herein, the OAG contended that the Gas Utilities should have hedged against such price risk.¹⁴³

98. \$15/Dth prices on February 11 did not place MERC on notice that prices would rise to the unprecedented level they ultimately did, or that MERC should have expected prices to continue to rise, or to reach anywhere close to where the prices settled.¹⁴⁴

99. While MERC knew of forecasted temperatures for the February Event, it did not know what actual temperatures would be on any given day. MERC was aware of supply production declines and the risk of possible supply cuts but had no way to reasonably predict the scale of potential production declines, how those supply shortages would impact the market (and for how long), or whether there would be cuts to MERC's supply.¹⁴⁵ MERC was also aware of the risk of incurring significant pipeline penalties. The penalties could have been up to three times the natural gas procurement costs during the February Event.¹⁴⁶

100. Given the limited tools available to MERC to respond to increases in customer requirements due to changes in weather or load variability or reductions in planned supply due to pipeline issues or supply cuts, and in light of the potential for punitive imbalance penalties, it was critical that MERC plan for adequate supply to meet customer load requirements.¹⁴⁷

101. All parties to this proceeding agree that the price spike that occurred during the February Event was unprecedented.¹⁴⁸ While the Gas Utilities had knowledge of increasing prices heading into the February Event, the historically unprecedented gas prices were not reasonably foreseeable.¹⁴⁹

102. As of February 16, the Gas Utilities knew that natural gas production failures had continued to increase considerably.¹⁵⁰ The U.S. Department of Energy's February 16 Situation Update (DOE Update) summarizes the circumstances over the previous

¹⁴² Ex. 406 at 7-10 (Mead Rebuttal).

¹⁴³ Ex. 603 at 12 (Lebens Surrebuttal).

¹⁴⁴ Ex. 401 at 35-36 (Eidukas Rebuttal).

¹⁴⁵ Ex. 406 at 6-7 (Mead Rebuttal).

¹⁴⁶ *Id.* at 27.

¹⁴⁷ *Id.* at 7.

¹⁴⁸ Ex. 506 at 13-14 (King Direct); Ex. 810 at 28 (Nelson Direct); Ex. 801 at 7 (Cebulko Direct); Ex. 604 at 12 (Lebens Surrebuttal).

¹⁴⁹ Ex. 406 at 3-7 (Mead Rebuttal); Ex. 506 at 59-61 (King Direct); Ex. 604 at 12 (Lebens Surrebuttal).

¹⁵⁰ Ex. 506 at 62 (King Direct).

weekend, including information the Gas Utilities would have known by that time.¹⁵¹ Specifically, the DOE Update states that “Extreme cold temperatures have led to sharp increases in gas demands for home heating and electricity generation across much of the Central U.S. At the same time, the cold 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.”¹⁵² Production outages represented “approximately 7% of total U.S. gas production.”¹⁵³ The DOE Update also states, “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.”¹⁵⁴

103. 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.¹⁵⁵ 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.¹⁵⁶

VIII. MERC’s Actions Before the February Event

A. Overview of MERC’s Gas Procurement Planning

104. MERC’s natural gas procurement strategy utilizes a variety of procurement tools to provide reliable, reasonably priced natural gas to its customers. MERC engages in advance planning to identify the need for and procurement of adequate pipeline transportation and storage resources and to procure adequate and diverse gas supplies, including hedged contracts and baseload gas supplies.¹⁵⁷

105. To meet the goals of providing reliable, reasonably priced natural gas to its customers while mitigating price volatility, MERC uses a diverse mix of firm gas supplies, including:

- (1) Fixed-price contracts (futures);

¹⁵¹ *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).

¹⁵² Ex. 506 at Sch. 11 at 7 (King Direct).

¹⁵³ *Id.* at Sch. 11 at 2.

¹⁵⁴ *Id.*

¹⁵⁵ *Id.* at Sch. 11; Ex. 100 at 49 (Smead Direct).

¹⁵⁶ Ex. 100 at 49 (Smead Direct).

¹⁵⁷ Ex. 400 at 15 (Eidukas Direct); *see also* Ex. 403 at 12-40 (Mead Direct). No party challenged MERC’s general gas procurement planning, including MERC’s geographic diversity of gas supply. Aside from the OAG’s conclusion that the natural gas utilities should have utilized certain financial hedging instruments, no party suggested MERC’s gas supply procurement was unreasonable or imprudent. Ex. 401 at 7 (Eidukas Rebuttal).

- (2) Pipeline storage contracts;
- (3) Financial calls (options);
- (4) FOM Index; and
- (5) Daily Spot Market – Gas Daily Index (GDD) or fixed prices.¹⁵⁸

106. The timeline for when MERC must take action on various aspects of its gas procurement is explained in the table below. Many decisions must be made well in advance of a particular winter or cold weather event.¹⁵⁹

Gas Procurement Chronology

Approximate Timeline Relative to a Cold Weather Event	Activity
Years in advance – prior to the heating season	Contracting for pipeline capacity
Years in advance – prior to the heating season	Contracting for storage capacity
During the spring/summer before the heating season	Issuing RFPs to secure seasonal baseload FOM gas purchases
During the spring/summer before the heating season	Implementing financial hedging instruments
During the spring/summer before the heating season	Issuing RFPs to secure call options for daily supplies
During the summer before the heating season	Contracting for gas supplies to inject into available contracted storage
Midmonth prior to each month during the heating season	Make any adjustments or add any baseload monthly gas supply deliveries for the upcoming month
A few days prior to the start of each month during the heating season	Nominate on the pipelines all baseload supply, and schedule expected storage withdrawals
25 hours in advance of the gas day and trading period (in the case of non-holiday weekdays)	Call on supplies pursuant to call option swing contracts
Prior to 9:00 a.m. the day ahead	Adjust storage, and secure any daily gas

¹⁵⁸ Ex. 400 at 15-16 (Eidukas Direct); Ex. 403 at 13 (Mead Direct).

¹⁵⁹ Ex. 403 at 17-18 (Mead Direct).

107. MERC also invests in conservation measures through its Conservation Improvement Program (CIP), which serves to reduce overall customer demand through increased efficiency.¹⁶⁰

108. MERC engages with the Commission for regular review and/or approval of certain gas procurement planning and activities in which it engages. MERC submits a number of filings with the Commission to provide for review of the Company's design day forecasting, pipeline entitlements, storage assets, natural gas procurement planning and policies, hedging plans, and gas commodity costs. These include:

- (1) An annual demand entitlement filing,
- (2) Annual automatic adjustment and true-up reports,
- (3) Monthly purchased gas adjustment reports, and
- (4) Periodic petitions for approval of variances to recover the costs of financial hedging instruments through the purchased gas adjustment.¹⁶¹

109. The Commission reviews MERC's gas capacity and supply contracting and costs on a routine basis to ensure the reasonableness of MERC's actions and decisions with respect to securing natural gas supply and transportation capacity along with other assets and contracts for adequate natural gas supply to meet customer needs.¹⁶²

110. Each year, MERC submits a demand entitlement filing for each of its PGA Areas (MERC-Consolidated and MERC-NNG) pursuant to Minn. R. 7825.2910, subp. 2 (2021). Through that filing, MERC describes changes to its demand entitlements, including pipeline capacity necessary to meet firm requirements for the upcoming heating season under design day conditions. Specifically, this filing includes analysis of firm customer demand requirements under the coldest expected temperatures based on historical weather over 25 years for the upcoming heating season and proposed changes to meet forecasted design day requirements and any other proposed demand entitlement changes. This process ensures that MERC's design day analysis is updated to reflect the most current information and that MERC contracts for adequate pipeline capacity to meet firm customer demand under the most extreme weather conditions.¹⁶³

111. For 2020-2021, MERC calculated a design day forecast of 57,065 Dth for MERC Consolidated and 280,796 Dth for MERC-NNG. Demand during the February Event did not reach this planning design day level, and temperatures across the areas MERC serves, while cold, did not reach design day temperature conditions¹⁶⁴

¹⁶⁰ Ex. 400 at 16, 20-21 (Eidukas Direct).

¹⁶¹ *Id.* at 16.

¹⁶² *Id.* at 16-17; *see also* Ex. 506 at 18 (King Direct).

¹⁶³ Ex. 400 at 17 (Eidukas Direct).

¹⁶⁴ *Id.* at 17-18.

112. MERC files its Annual Automatic Adjustment (AAA) report pursuant to Minn. R. 7825.2390-.2920 (2021), and specifically, reporting requirements outlined in Minn. R. 7825.2800-.2840. Through the AAA review, the Department and Commission review annual gas prices, daily delivery variance charges, curtailment and balancing penalties imposed, pipeline transportation sources, diversity of gas supplies, capacity release practices, purchasing practices, storage contracts and costs, and hedging practices. The AAA report details MERC's policies and procedures concerning its purchases of natural gas.¹⁶⁵ MERC also submits detailed information regarding its hedging program in each AAA Report, including:

(1) A clearly defined and quantified description of the risk MERC is insuring against by implementing its hedging strategies and a clearly defined estimate of the probability of the events occurring.¹⁶⁶

(2) A quantitative analysis of the value of reducing price volatility and managing price risk through MERC's hedging program (the cost and benefit of these programs to all customers and the companies) that includes: (1) a comparison of what actual low, average, and high usage customer bills (on a monthly basis) would have been with and without the use of the hedging strategies as implemented during the relevant time period; and (2) a comparison of what these customer bills would have been under budget billing, assuming normal gas usage for low, average, and high-usage customers, and assuming catastrophically high prices.¹⁶⁷

(3) A full post-mortem analysis of their hedged volumes for the preceding heating season compared to other hedging strategies and the prevailing market prices strategy.¹⁶⁸

(4) Data on the relative benefits of price-hedging contracts, including the average cost per dekatherm for natural gas purchased under financial instruments compared to the comparable monthly and daily spot index prices.¹⁶⁹

113. Each month, MERC submits a report for each of its PGA Areas (MERC-Consolidated and MERC-NNG) pursuant to Minn. R. 7825.2910, subp. 1. Through that filing, the Company provides information detailing the calculation of the monthly PGA, the calculation of the weighted average cost of gas (WACOG) to be effective in the upcoming month, revised tariff sheets defining retail rate revisions by rate schedule, daily delivery variance charge information, estimated previous month and year-to-date commodity

¹⁶⁵ *Id.* at 18.

¹⁶⁶ See *In re the Review of the 2008 Annual Automatic Adjustment Reports and Annual Purchased Gas Adjustment True-Up Filings of All Gas Utilities*, MPUC Docket No. G999/AA-08-1011, Order Acting on Certain Gas Utilities' Annual Reports and True-Up Proposals and Setting Further Requirements (Mar. 2, 2010).

¹⁶⁷ See *id.*

¹⁶⁸ See *In re a Petition Submitted by Minnesota Energy Resources Corporation (MERC) Requesting Approval for an Extension of Variances to Minnesota Rules 7825.2400, 7825.2500 and 7825.2700 (the Purchased Gas Adjustment Rules)*, MPUC Docket No. G007,011/M-11-296, Order (Aug. 17, 2011).

¹⁶⁹ See *id.*

delivered gas cost by supplier, and a statement of changes in commodity costs, as compared to the previously submitted PGA report.¹⁷⁰

114. MERC also submits periodic filings seeking Commission authorization to engage in hedging and to extend necessary rule variances related to hedging activities.¹⁷¹ In its periodic petitions for continued authority to engage in hedging, MERC provides information and analysis demonstrating that customers benefit from hedging and that there is not an undue price premium paid for such hedging.¹⁷² In approving MERC's hedging petitions, the Commission has established limitations on hedging, including limiting the types of hedging instruments the Company may use and applying a cap to the volume of gas supply that may be hedged.¹⁷³

115. In authorizing MERC's hedging program, the Department and Commission have recognized that hedging acts as an "insurance policy" to protect customers from price spikes in the natural gas market.¹⁷⁴

116. MERC's goal with respect to hedging is to have a balanced approach that provides price protection for a portion of supply. MERC's financial hedging is focused on monthly prices increasing over forward prices, and is not designed to mitigate against the risk of daily market price spikes.¹⁷⁵

117. MERC uses a series of steps and processes to plan for and secure gas supply and related purchases. MERC's overall objectives for its gas supply portfolio are to provide reliable and reasonably-priced natural gas for sales customers. These objectives are accomplished through utilizing diverse purchase locations, multiple counterparties, firm transportation contracts, storage, hedging, FOM supply, wing supply, or "call options," and daily priced supply, including multiple supply sources, providing a diversity of supply points and prices where possible. MERC determines supply requirements for its customers on a daily, monthly, and seasonal basis.¹⁷⁶

B. MERC's Gas Procurement Before the February Event

1. Customer Demand and Design Day Planning

118. To plan for customer demand during the winter heating season, MERC must ensure there is enough contracted interstate pipeline capacity to provide firm delivery of natural gas to its firm customers on a peak day. MERC's natural gas supply policy is to

¹⁷⁰ Ex. 400 at 19 (Eidukas Direct).

¹⁷¹ *Id.* Hedging means reducing or controlling risk. A hedge is an investment or position taken in the futures market that is opposite to the one in the physical market with the objective of reducing or limiting risks associated with adverse price movements in an asset. *Id.* at 19 n. 5.

¹⁷² *Id.* at 19-20.

¹⁷³ See *In re the Petition of Minnesota Energy Resources Corporation for Extension of Rule Variances to Recover the Costs of Financial Instruments Through the Purchased Gas Adjustment*, MPUC Docket No. G011/M-20-833, Order (Apr. 9, 2021).

¹⁷⁴ *Id.*; Ex. 400 at 20 (Eidukas Direct).

¹⁷⁵ Ex. 400 at 19 n.5 (Eidukas Direct).

¹⁷⁶ Ex. 403 at 12, 14 (Mead Direct).

have adequate firm transportation capacity to protect against a one-in-twenty-year cold weather event, plus a positive reserve margin. Because MERC's service territories are geographically spread throughout the state, MERC contracts for firm pipeline capacity on NNG, Great Lakes, Viking, Centra, and Northern Border.¹⁷⁷

119. For the 2020-2021 winter heating season, MERC planned to meet the supply for forecasted design day load through a combination of monthly baseload, call options, daily priced gas purchases, and storage supplies; however, winter 2020-2021 peak day demand never reached the design day forecast.¹⁷⁸

120. The design day forecast identifies the coldest adjusted heating degree days since January 1996 for a variety of weather stations within the MERC-NNG and MERC-Consolidated service areas. MERC then utilizes the last three years of weather for December, January, and February, and firm system sales load, to calculate forecasted firm customer demand under design day conditions, using regression analysis.¹⁷⁹

121. When forecasting design day customer demand, MERC excludes all interruptible customers in the design day. Therefore, the design day forecast only includes firm customer sales volumes.¹⁸⁰

122. The following table summarizes MERC's design day forecasts for MERC-Consolidated and MERC-NNG for each of the pipelines used to serve customer load requirements.¹⁸¹

2020-2021 Design Day Forecasts

Pipeline/PGA	Design Day Forecast (2020-2021)
Centra/Consolidated	9,364 Dth
Great Lakes/Consolidated	30,279 Dth
Viking/Consolidated	17,422 Dth
Total Consolidated	57,065 Dth
NNG	280,796 Dth

a. Interstate Pipeline Transportation Capacity

123. To meet its forecasted design day load obligation and ensure adequate supply, capacity, and storage on a peak day, MERC contracts for firm transportation

¹⁷⁷ *Id.* at 20.

¹⁷⁸ *Id.* at 21. Schedule 3 displays the five highest firm customer sendout days during the 2020-2021 winter heating season and the corresponding forecasted peak winter volumes. As shown in Schedule 3, despite the February Event, from November 2020 through March 2021, peak day usage never exceeded MERC's design day forecast for the period. Ex. 404 at Sch. 3 (Mead Direct Schedules).

¹⁷⁹ Ex. 403 at 19 (Mead Direct).

¹⁸⁰ *Id.*

¹⁸¹ *Id.* at 20. These design day forecasts were approved in MPUC Docket Nos. G011/M-20-636 (MERC-Consolidated) and G011/M-20-637 (MERC-NNG) by Orders issued January 25, 2021. *Id.*

capacity to allow for the delivery of contracted natural gas supplies to specified delivery points where the interstate pipelines interconnect to MERC's distribution system.¹⁸²

b. Baseload Gas Purchases

124. MERC's baseload gas supply is the first layer of supply used to meet customer requirements. Baseload is the same volume every day for a given period and typically priced at a FOM index. Baseload gas ensures a level of reliability for the period contracted for, that it will be there and can be planned on. Because baseload gas supply is delivered every day of the contract, all storage activity, call options, and daily purchases are layered on top of it.¹⁸³ Baseload purchases avoid the daily spot price by instead using a FOM index price or a fixed price, so they provide both quantity and price certainty. However, baseload purchases provide a fixed volume each day, so they do not provide the flexibility that swing supply does.¹⁸⁴

125. MERC annually forecasts system demand for both the NNG and Consolidated systems. To determine the level of baseload purchases for each month over the winter season, MERC takes into account storage withdrawal/injection rights, historical seasonal weather variations, market factors, and daily operational flexibility, among other variables. MERC generally will maximize the amount of baseload purchases while ensuring sufficient operational flexibility to balance load variability through the winter heating season. In Minnesota, daily temperatures over a given winter month can vary significantly, and it is necessary to have more flexible supply to balance those variations.¹⁸⁵ Ultimately, the Department reviews and the Commission approves MERC's annual gas costs as part of the AAA process each year, including the volume of baseload gas purchases.¹⁸⁶

126. MERC completed its planning for and execution of baseload purchases in late April 2020 for the 2020-2021 winter, which is consistent with past practice.¹⁸⁷

127. For February 2021, MERC had 94,640 Dth/day of contracted baseload supplies for the MERC-NNG PGA.¹⁸⁸

128. The Department reviewed MERC's February baseload volumes and approach to determining baseload quantities and did not dispute that MERC's level of baseload volumes was within the range of reasonableness.¹⁸⁹

¹⁸² *Id.* at 22. Schedule 5 shows the capacity utilization for the Company's transportation contracts. This exhibit shows capacity utilization, capacity release volumes, capacity that was part of MERC's AMA, and the combination of these three elements. Additionally, capacity needed for call options is shown, but not included in the total utilization values. *Id.*; see also Ex. 404 at Sch. 5 (Mead Direct Schedules).

¹⁸³ Ex. 403 at 28 (Mead Direct); see also Ex. 506 at 21 (King Direct).

¹⁸⁴ Ex. 506 at 21 (King Direct).

¹⁸⁵ Ex. 403 at 29 (Mead Direct).

¹⁸⁶ *Id.* This AAA review occurs after the fact and is not a preapproval of MERC's gas purchases.

¹⁸⁷ *Id.*

¹⁸⁸ *Id.* at 47; Ex. 408 at 27 (Sexton Direct).

¹⁸⁹ Ex. 506 at 34-39 (King Direct).

129. MERC developed and implemented a reasonable baseload purchasing plan based upon the information available at the time prior to the February Event. MERC's procurement of baseload volumes for February 2021 was reasonable and prudent.

130. MERC's baseload gas purchase avoided an estimated \$76 million in additional costs for MERC-NNG during the February Event.¹⁹⁰

c. Geographic Diversity of Supply

131. Among the issues identified in the Commission's Order for Hearing, the Commission directed that this proceeding address whether the Gas Utilities had enough geographic diversity of gas supply.¹⁹¹

132. Geographic diversity of supply refers to the ability of the Gas Utilities to acquire gas supply from a variety of locations. As purchasers of gas, the Gas Utilities' geographic diversity of supply is ultimately tied to the transportation arrangements they hold with pipelines, which specify receipt points where the utilities have rights to receive gas and then ship it to the delivery point (i.e., the point at which the utility system connects with the interstate pipeline).¹⁹²

133. Alternative pipeline capacity cannot be readily obtained, and causing it to be built would require ongoing, fixed costs at a significant level. These additional fixed costs would need to be justified on a cost basis.¹⁹³

134. MERC appropriately utilized the geographic diversity in its portfolio to minimize exposure to rising daily gas prices during the February Event. Based on the physical location of MERC-NNG's PGA area markets and its portfolio of firm pipeline services, the only sources available to obtain required incremental daily natural gas supply during the February Event were at Northern-Ventura and to a much smaller degree at Northern-Demarc. MERC had no alternative supply locations available during the February Event to meet daily requirements in the MERC-NNG PGA area.¹⁹⁴

135. No party in this proceeding has disputed that MERC had sufficient geographic diversity of supply during the February Event.¹⁹⁵

136. The record establishes that MERC had a reasonable and prudent geographic diversity of supply.¹⁹⁶

¹⁹⁰ Ex. 400 at 32 (Eidukas Direct); Ex. 403 at 57 (Mead Direct).

¹⁹¹ Order for Hearing at 22.

¹⁹² Ex. 506 at 42 (King Direct).

¹⁹³ *Id.* at 49.

¹⁹⁴ Ex. 408 at 13 (Sexton Direct); Ex. 409 at 3-4 (Sexton Rebuttal).

¹⁹⁵ See Ex. 401 at 7 (Eidukas Rebuttal).

¹⁹⁶ See Ex. 409 at 3-4 (Sexton Rebuttal).

d. Swing Supply/Call Options for Gas

137. MERC contracted for swing supply, which it calls “call options” during the 2020-2021 winter period. Swing supply provides a gas utility with the right to call upon gas supply for a certain number of days for a specific period and location with a predetermined price, typically priced around the daily market.¹⁹⁷

138. Swing supply plays a role in ensuring that MERC can reliably serve customer needs. The benefit of swing supply is to secure firm supply on days when it is needed without having the requirement to pay for the gas when it is not needed or risk having to sell the gas during low-demand days at a loss. To have the ability to call on gas through swing supply ensures the supply will be there on a cold day or during peak days. Typically, utilities are required to call on swing supply for an entire trading window and the gas is priced at daily market indices. For example, if gas is needed on a Monday, the entire weekend would need to be called upon, Saturday, Sunday, and Monday, in equal volumes (i.e., ratable volumes). If there happens to be a holiday, that is also included in the trading window.¹⁹⁸

e. Daily Gas Purchases

139. MERC plans to meet customer load requirements in excess of available baseload, storage withdrawals, and call options with daily spot market purchases.¹⁹⁹

140. The use of daily supply purchases provides needed flexibility to address the reality of variability in weather and customer load day-to-day during the month or the heating season. In particular, daily purchases provide operational flexibility during months where the range in temperatures can be large, such as February.²⁰⁰

141. In MERC’s normal practice, the business day before flow date,²⁰¹ MERC analyzes the forecast for accuracy based on previous days or previous similar weather prior to 7:30 a.m. In extreme weather conditions, MERC will analyze the forecast one and half business days before the flow date.²⁰²

142. Once the forecast is reviewed, the gas supply traders ensure there is sufficient firm capacity within MERC’s portfolio on the pipelines needed to serve the load. First, the trader subtracts off from the forecast an estimate of what transport customers will be delivering. Next, the trader takes into consideration what natural gas supplies MERC already has flowing (i.e., baseload purchases for the month or season), storage withdrawal limits and availability, and call deals; and determines a plan to supply

¹⁹⁷ Ex. 403 at 36 (Mead Direct). Schedule 2 is a listing of natural gas purchases or deals by price type for February 2021, specifically call deals are labeled “Call Option.” *Id.*; Ex. 404 at Sch. 2 (Mead Direct Schedules).

¹⁹⁸ Ex. 403 at 37 (Mead Direct).

¹⁹⁹ *Id.* at 37-38.

²⁰⁰ *Id.*

²⁰¹ The flow date or gas day runs from 9 a.m. to 9 a.m. Central. For weekends, this date is the Friday before. For holidays, it is the business day immediately preceding the holiday. *Id.* at 38 n.6.

²⁰² *Id.* at 38.

customer requirements. If there is a shortfall after storage withdrawals are maxed out and call deals have been called on, only then does MERC purchase additional supply on the daily market utilizing available firm capacity on the relevant pipeline.²⁰³

143. If additional supply is to be purchased on the daily market, typically before 8:15 a.m., MERC will send out a Request for Price on the Intercontinental Exchange (ICE) trading platform to three or more counterparties with which MERC has North American Energy Standards Board (NAESB) contracts, requesting to bid on MERC's volume needs at a settled index price. Typically by 8:30 a.m., the bids are reviewed, and purchases are completed based on the least cost supply that will fill the forecasted needs. Once the supply is procured, MERC nominates it on the pipeline for the timely cycle. Timely cycle is due at 1:00 pm for most pipelines.²⁰⁴

144. In the afternoon, MERC's Gas Supply Group reviews the forecast and compares it to the scheduled/nominated supply for the current and upcoming days.²⁰⁵

145. The daily index price, which is calculated based on the average of all reported fixed-price sales, is not published until later that night.²⁰⁶

146. On the NNG pipeline, just before the gas day ends at around 7:15 a.m., MERC calculates the estimated load for that gas day (ending at 9:00 a.m.) and adjusts the storage nomination to better match the actual flow to minimize daily imbalances.²⁰⁷

147. The record shows that MERC's general gas procurement, planning, and implementation for the 2020-2021 winter heating season, and prior to and during the February Event, were prudent and reasonable. Overall, MERC's actions before the February Event were prudent and reasonable.

C. Disputed Issue Related to MERC's Planning: Use of Hedging Instruments

1. Overview of Hedging

148. Hedging means reducing or controlling risk associated with market price volatility.²⁰⁸ In the context of purchasing natural gas, hedging can take the form of physical or financial hedging.²⁰⁹

149. An example of physical hedging is purchasing natural gas during the summer when prices are low and storing it for later use during the winter.²¹⁰

²⁰³ *Id.* at 38-39.

²⁰⁴ *Id.* at 39.

²⁰⁵ *Id.*

²⁰⁶ *Id.*

²⁰⁷ *Id.*

²⁰⁸ Ex. 403 at 33 (Mead Direct).

²⁰⁹ Ex. 600 at 3 (Lebens Direct).

²¹⁰ *Id.*

150. Financial hedging often involves derivatives, such as options and futures contracts.²¹¹ For example, a “call” option gives the owner of the option the right, but not the obligation, to buy a specific amount of a commodity at a specific price for a limited period of time.²¹² In such circumstances, a hedge is an investment or position taken in the futures market that is opposite to the one in the physical market with the objective of reducing or limiting risks associated with adverse price movements in an asset.²¹³

151. MERC uses natural gas price hedging tools for a portion of its gas supply portfolio to mitigate risks associated with significant price increases of natural gas purchased each winter. MERC has developed and implemented a hedging strategy that targets price protection for 60 percent of normal winter volumes – 30 percent through physical storage and 30 percent through financial instruments (10 percent futures and 20 percent options).²¹⁴

152. MERC hedges winter months with these contracts executed in the preceding summer months. Specific to 2021, MERC purchased all winter (November 2020-March 2021) financial contracts by the end of October 2020. MERC hedges against NYMEX volatility, which provides protection from monthly market volatility.²¹⁵

153. Available hedging tools are monthly-oriented similar to baseload purchases. As a result, these tools are ineffective with respect to gas purchased using daily price indices and as a result do not mitigate daily price spikes.²¹⁶

154. MERC uses hedging to reduce its month-to-month price swings in the PGA. Ideally, the PGA would have less price volatility than the market index price volatility, but it is not expected that the PGA would be lower than the market index price over time, because there are costs associated with hedging, and the objective of hedging for the Gas Utilities is not to beat the market.²¹⁷

155. In its April 25, 2019, review of 2017-2018 AAA Reports in Docket No. G999/AA-18-374, the Department described the goal of hedging to be to “use appropriate strategies to minimize the risk of cost increases for any given level of reduced volatility. In a sense, a hedge is an insurance policy that, for a fee, protects utilities (and their ratepayers) against a specific (unfavorable) event occurring during the term of a policy.” Hedging should not be expected to reduce the average price of gas purchases

²¹¹ *Id.*

²¹² *Id.* at 4.

²¹³ Ex. 403 at 33 (Mead Direct).

²¹⁴ *Id.*

²¹⁵ *Id.*

²¹⁶ Ex. 409 at 12-13 (Sexton Rebuttal); Ex. 506 at 23 (King Direct).

²¹⁷ Ex. 403 at 34 (Mead Direct); *see also* Ex. 506 at 76 (King Direct) (“I do not believe the Gas Utilities should be expected to systematically beat the index or engage in a behavior that risks increased cost without having the parameters for doing so established and agreed to in advance.”).

over time and, in its purest form, does not provide a means to reduce the expected price of gas.²¹⁸

156. Hedging protects against market volatility, but this strategy requires a balanced approach. The more a company hedges, the higher the reduction of volatility. However, hedging more risks over-hedging (e.g., procuring gas supplies in excess of actual customer load), especially when winter volumes change due to weather and other factors. In addition, the higher the hedging percent, or the more volume that is locked at a price, the less opportunity there is to benefit from a falling gas market, which risks ultimately increasing customers' gas costs.²¹⁹

157. MERC is authorized to financially hedge up to 30 percent of expected winter volumes. This reduces the risk of being in an over-hedged situation during a warm winter, while still reducing volatility.²²⁰

158. As with storage supply, MERC purchased financial products from May through October 2020.²²¹ MERC is required to report, in its annual Demand Entitlement filing filed on or before November 1 each year, a list of all financial instrument arrangements entered into for the upcoming heating season, the cost premium associated with each contract, the size of the contract, the contract price, and to provide a detailed discussion of the anticipated benefits to customers associated with completed hedging instrument contracts.²²²

2. Prudence of MERC's Use of Hedging Tools

159. As a public utility, MERC's hedging objectives are to provide continuous and reliable gas supply at a reasonable overall price relative to the alternative market prices at that time (including the premium associated with the hedges), while providing reasonable protection from market volatility.²²³

160. The Commission has established conditions to ensure hedging is designed to provide a value to customers as insurance at an overall reasonable price (inclusive of the premium required to procure that insurance).²²⁴ The timing and instruments used in MERCs hedging program are subject to Commission review and approval.²²⁵

161. Department 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 than

²¹⁸ Ex. 403 at 34 (Mead Direct).

²¹⁹ *Id.* at 34-35.

²²⁰ *Id.* at 35.

²²¹ *Id.* at 36.

²²² *In re the Petition of Minnesota Energy Resources Corporation for Extension of Rule Variances to Recover the Costs of Financial Instruments Through the Purchased Gas Adjustment*, MPUC Docket No. G011/M-20-833, Order (Apr. 9, 2021).

²²³ Ex. 401 at 13 (Eidukas Rebuttal).

²²⁴ *Id.* at 13-14.

²²⁵ *Id.* at 12.

a transient spike.”²²⁶ “Financial hedges typically point to monthly FOM prices as opposed to daily prices.”²²⁷

162. The OAG contends 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. The OAG further argued that over-the-counter (OTC) type contracts, if planned sufficiently in advance, could have completely avoided extraordinary gas costs during the February Event.²²⁸ 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.²²⁹ The OAG recommends a disallowance of up to \$64,975,882 for MERC (all of its incurred extraordinary costs).²³⁰

163. The OAG’s arguments rely on the testimony of its witness, Brian Lebens, who provided information regarding potential hedging instruments that he believes the gas utilities, including MERC, could have pursued to offset part, and even potentially all, of the cost of the price spike during the February Event.²³¹

164. Mr. Lebens testified that the utilities could have utilized “daily options, weekly options, and short-term options” as traded on the CME Group platform to mitigate extraordinary costs. Mr. Lebens suggested the utilities could have pursued “customizable [OTC] contracts that cap the maximum price that they would have paid.” Finally, Mr. Lebens suggests that the utilities could have used Weather Futures and Options to hedge price risk during the February Event.²³²

165. Mr. Lebens acknowledged that he is not aware of any such daily, weekly, or short-term hedges or exchange-traded hedges at Ventura or Demarc that were traded in the market during 2021.²³³ He also 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.²³⁴

²²⁶ Ex. 506 at 23 (King Direct).

²²⁷ *Id.*

²²⁸ Ex. 603 at 13 (Lebens Surrebuttal).

²²⁹ Ex. 604 (Lebens Written Summary of Pre-Filed Testimony).

²³⁰ Ex. 600 at 43 n.91 (Lebens Direct); *see also* Ex. 603 at 17 (Lebens Surrebuttal).

²³¹ *See* Ex. 600 at 6-14 (Lebens Direct); *see also* Ex. 409 at 13-14 (Sexton Rebuttal).

²³² Ex. 600 at 6 (Lebens Direct).

²³³ *Id.* at 8, 10.

²³⁴ *Id.* at 10-11. The OAG contends that Mr. Lebens’ acknowledgements are irrelevant because the Gas Utilities must prove they acted prudently, and it is not the OAG’s burden to show that they acted imprudently. *See* OAG Reply Br. at 4 (Mar. 25, 2022) (eDocket No. 20223-184153-02). The OAG maintains that it has no burden to establish that hedges tied to Demarc and Ventura existed, but instead that MERC must show these hedging products did not exist. *Id.* The OAG has proposed that the Commission should disallow a substantial portion, if not all, of the extraordinary gas costs incurred by the Gas Utilities. In doing so, the OAG has an obligation to adequately support its recommendations and ensure that the evidence it offers is reliable. To the extent that a witness lacks knowledge or familiarity with issues related to the opinions offered, those opinions are less reliable and persuasive.

166. During the evidentiary hearing, Mr. Lebens indicated that he was “not sure” whether he had reviewed the Commission orders related to MERC’s hedging.²³⁵ Mr. Lebens was not aware that, in obtaining approval to engage in hedging, MERC was required to demonstrate the benefits of its proposed hedging plans, and he was unaware that MERC is required to file detailed information regarding its hedges in advance of each heating season.²³⁶ Further, 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 should have performed to be found prudent.²³⁷

167. MERC offered the testimony of Timothy Sexton, who testified that he was not aware of any financial hedging tools that could have been utilized by MERC to mitigate intra-month daily price spikes during the February Event.²³⁸ Mr. Sexton also testified that he is not aware of any actively traded hedging instrument designed to provide a hedge against daily price indices at either of Northern-Ventura or Northern-Demarc pricing locations.²³⁹ The Gas Utilities’ witness, Mr. Smead, opined that the suggestions made in the OAG testimony are either a highly risky commodity-speculation strategy, posit price-protection tools that would be prohibitively expensive, or do not exist.²⁴⁰

168. MERC-NNG is able to purchase incremental daily supplies only at Northern-Ventura, and to a much lesser extent, Northern-Demarc.²⁴¹ To offset daily price risk without incurring speculative locational price risk MERC would need to use hedging instruments priced based on these locations.²⁴²

169. In his surrebuttal testimony, Mr. Lebens addressed swing futures, stating that they “allow a utility to lock-in the price of gas at a specific location like Ventura or Demarc ahead of time.”²⁴³ He proposed that, with enough advanced planning, a utility could negotiate with another party to mimic a swing future using an OTC-style contract.²⁴⁴

²³⁵ Evidentiary Hearing Tr. Vol. 3 at 49 (Lebens).

²³⁶ *Id.* at 49-50.

²³⁷ *Id.* at 50-51. Mr. Lebens further testified that he is not aware of any proceeding before the Commission in which the Commission had previously discussed the financial hedging strategies he is talking about and indicated that it would bear on prudence. *Id.* at 51. The OAG proposed a finding of fact indicating that this testimony and the questions that elicited it are not relevant to this proceeding, because the Commission does not approve hedging plans or direct utilities to engage in hedging, it only authorizes the recovery of costs incurred in connection with hedging. See OAG Redlined MERC’s Proposed Findings of Fact, Conclusions of Law, and Recommendation at 6 (Mar. 25, 2022) (eDocket No. 20223-184153-03). The OAG is proposing, however, that the utilities should have made large-scale changes in their hedging practices, including changes it contends should have been made long before the February Event. The Commission’s approach to hedging, its expectations about how hedging will be used by the utilities, and statements that the Commission has made to the utilities about these issues, are relevant to determining whether the utilities were required to hedge as urged by the OAG in order to be deemed to have acted prudently.

²³⁸ Ex. 409 at 13-14 (Sexton Rebuttal).

²³⁹ *Id.* at 13.

²⁴⁰ Ex. 101 at 3 (Smead Rebuttal)

²⁴¹ Ex. 409 at 13 (Sexton Rebuttal).

²⁴² *Id.* at 14.

²⁴³ Ex. 603 at 11 (Lebens Surrebuttal).

²⁴⁴ *Id.*

The OAG contends that swing futures were available priced at Ventura and Demarc on the ICE.²⁴⁵

170. In response to an information request from the OAG on swing futures at Demarc or Ventura, MERC responded:

Prior to the event, MERC was aware of the Swing Futures product from the Intercontinental Exchange and was aware of its volatile liquidity. Counterparties who buy a Swing Future pay a fixed price and receive a floating daily price for a certain delivery period and delivery point. It is important to note that in order to mitigate the cost risks associated with price volatility, MERC would only enter into this type of financial transaction (Swing Future) if it also entered into a physical transaction for the same delivery period and same delivery point. As stated in MERC's May 20, 2021 Reply Comments filed in docket 21-135; "The largest drawback for this product is that it is most volatile during pending cold periods. Market participants would need to predict a price-event beforehand." In addition, there is a high probability that MERC or anyone else would miss the opportune time to layer on these hedges without hindsight, layering on these hedges when the pricing does not move, resulting in no benefit and increasing sunk costs with the fixed prices. Given these identified drawbacks, MERC has not entered into any Swing Futures.²⁴⁶

171. Weather derivatives are not designed to hedge gas prices, because they are not correlated to the price of gas. Rather, these are tools by which a utility might hedge against the risk that distribution service revenues are below associated forecasts due to warmer than average temperatures during the winter season. As such, these tools are not suited to hedge against daily gas price risk.²⁴⁷

172. Even if a weather derivative were utilized by a utility such as MERC-NNG to hedge overall costs and revenues, a weather derivative based upon weather in a location far removed and with minimal correlation to Minnesota weather, such as the Dallas weather derivative cited by Mr. Lebens, would not represent a reasonable choice to hedge weather risk in Minnesota. That is, even if the kind of weather derivative suggested by Mr. Lebens were available, the record does not show how it would have provided price protection for MERC with respect to the Northern-Demarc and Northern-Ventura daily index price.²⁴⁸

173. The daily options, weekly options, and short-term options suggested by the OAG are not designed to hedge price risk associated with natural gas purchases at NNG-Ventura and NNG-Demarc because these options are settled based upon the price of natural gas at Henry Hub, Louisiana. It is not reasonable to utilize an option priced at

²⁴⁵ *Id.* at Sch. 2, 3.

²⁴⁶ *Id.* at Sch. 2 at 3.

²⁴⁷ Ex. 409 at 16 (Sexton Rebuttal).

²⁴⁸ *Id.* at 17-18.

Henry Hub, Louisiana to hedge against natural gas price risk at NNG-Ventura or NNG-Demarc.²⁴⁹

174. As illustrated in the table below, the market price of natural gas at Henry Hub was very different than the market price of natural gas at Ventura or Demarc during the February Event.²⁵⁰

Daily Natural Gas Pricing During February Event

Date	Gas Daily Midpoint Index Price for day of Delivery (\$/MMBtu)		
	Henry Hub	Northern – Demarc	Northern - Ventura
02/13/2021	\$6.000	\$231.670	\$154.905
02/14/2021	\$6.000	\$231.670	\$154.905
02/15/2021	\$6.000	\$231.670	\$154.905
02/16/2021	\$6.000	\$231.670	\$154.905
02/17/2021	\$16.995	\$133.635	\$188.320

175. If MERC-NNG had purchased a call option with a strike price of \$4 per MMBtu with delivery at Henry Hub, this would have provided MERC-NNG with the right to resell the call option at a market value of about \$2 per MMBtu immediately prior to gas flow (\$6 per MMBtu Henry Hub Index price less \$4 per MMBtu Call Option strike price). Netting this \$2 option value gain against MERC-NNG’s daily gas purchase price would have provided very little offset versus the historically high Ventura and Demarc daily gas prices incurred during the February Event.²⁵¹

176. To the extent the OAG’s proposal is for MERC to trade in Henry Hub options to mitigate the cost of gas to MERC’s customers, the proposal would require MERC to engage in financial speculation in a market in which it would not otherwise participate. To the extent OAG’s proposal is for MERC to purchase options speculatively in markets that it does participate in, the OAG does not articulate a principle that MERC could apply to determine when it would be prudent to use ratepayer money to buy call options to time price spikes.

177. The OAG contends its proposal to incorporate a ceiling and a floor to create hedged swing contracts would have managed price risk in nearly all situations.²⁵² The OAG also argues that review of the “price action that occurred for actual hedges during February 2021” is useful “because it mimics how other hedges would have performed, and because it mimics how hedged swing contracts would have performed if they had been in place.”²⁵³

²⁴⁹ *Id.* at 18-19.

²⁵⁰ *Id.* at 19.

²⁵¹ *Id.*

²⁵² See Ex. 600 at 17-18 (Lebens Direct) (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).

²⁵³ Ex. 603 at 3 (Lebens Surrebuttal).

178. However, the “current monthly call options” Mr. Lebens suggests the gas utilities, including MERC, could have purchased to hedge against February gas costs were actually for deliveries in March 2021. February call options were not available at the time Mr. Lebens suggests these options should have been purchased.²⁵⁴ Additionally, the OAG’s suggested options are for purchases at Henry Hub in Erath, Louisiana and not any of the delivery points where MERC purchases gas to serve its Minnesota customers.²⁵⁵

179. The OAG contends that its analysis of actual hedges was not an argument that the utilities should have executed those specific hedges, but instead the OAG intended to illustrate how the utilities could have achieved savings had they priced protections into their contracts for swing supply, in advance.²⁵⁶

180. The OAG also suggested the utilities should have used costless collars, which Mr. Lebens asserts “do not cost anything.”²⁵⁷ MERC critiques Mr. Lebens’ testimony because he considered collars that are CME options based on futures contracts for purchase at Henry Hub, not Demarc or Ventura. MERC also notes that the put or floor price obliges the buyer to purchase a futures contract even if the floor price is higher than the current market price.²⁵⁸ MERC contends it could not have acted in the way proposed by the OAG to avoid the price spike during the February Event.²⁵⁹

181. Costless collars are appropriate to hedge baseload gas supply that a utility is certain it will purchase during the winter. They are not suited, however, as a hedging mechanism for swing supplies purchased at daily index prices.²⁶⁰

182. Further, a costless collar is a structured product that requires three components to operate effectively. These three components include the purchase of a call option, the sale of a put option, and the purchase of baseload supply.²⁶¹

183. As swing supplies represent weather dependent supplies only required under certain conditions, a utility, such as MERC-NNG, has no certainty if these supplies will be required and purchased. Absent certainty that physical supply will be needed, one of the three components required to utilize a costless collar, the baseload supply

²⁵⁴ Ex. 410 at 3 (Sexton Written Summary of Pre-Filed Testimony); see *also* Ex. 409 at 20-22 (Sexton Rebuttal).

²⁵⁵ Ex. 409 at 18 (Sexton Rebuttal) (“As illustrated in Schedule BPL-D-1, BPL-D-2, and BPL-D-3 to Mr. Lebens’s Direct Testimony, each of these three Options are settled based upon the price of natural gas at Henry Hub, Louisiana.”); Ex. 101 at 6 (Smead Rebuttal) (“All CME products require trades at Henry [Hub] in Erath, Louisiana. The Joint Utilities’ market is in Minnesota, over 1,000 miles away.”); Evidentiary Hearing Tr. Vol. 3 at 17-18 (Lebens) (“Q: You’re aware that these contracts are priced based on the price of natural gas at Henry Hub located in Erath, Louisiana, correct? A: Yes.”).

²⁵⁶ OAG Reply Br. at 10 (Mar. 25, 2022) (eDocket No. 20223-184153-02).

²⁵⁷ Ex. 600 at 20, 29 (Lebens Direct).

²⁵⁸ Ex. 101 at 12-14 (Smead Rebuttal).

²⁵⁹ *Id.* at 17.

²⁶⁰ Ex. 409 at 23 (Sexton Rebuttal).

²⁶¹ *Id.*

purchase, is absent and as such, a costless collar cannot be acquired to support hedging of swing supply purchases.²⁶²

184. The record does not show that such collars on swing supplies as suggested by Mr. Lebens could take place, or that there would be willing counterparties to such collars. Further, MERC offered evidence that placing hedges on swing supplies would not be feasible and would result in significant costs and restrict operational flexibility.²⁶³ Only one approach fits Mr. Lebens' recommendations on placing hedges on swing supplies, and it would be very expensive, even if available.²⁶⁴

185. When planning for a winter season, MERC-NNG plans to make swing purchases at daily prices for supply requirements that may or may not be needed depending upon weather conditions. As a result, sales of put contracts (such as those in costless collars) is not a reasonable strategy to hedge against swing natural gas purchases. Mr. Lebens also discussed limits on selling puts.²⁶⁵

186. The record establishes that MERC's use of hedging instruments as part of its gas procurement planning for the 2020-2021 winter was prudent and reasonable. The record does not establish that prudence required MERC to engage in the hedging strategies urged by the OAG, that it even would have been able to do so, or that there are specific, measurable costs that would have been avoided had MERC done so.

187. If the Commission wishes to consider reevaluating the utilities' use of hedging strategies and products in order to mitigate price risk, it may wish to explore these issues in connection with its forward-looking docket. In connection with the February Event, however, MERC did not act imprudently by not procuring hedging instruments as recommended by the OAG. Therefore, the Commission should not disallow extraordinary gas cost recovery to MERC on the basis of its hedging.

IX. MERC's Actions During the February Event

A. General Timeline of MERC's Actions Leading Up to and During the February Event

188. Beginning February 4, 2021, NNG called a SOL with zero percent System Management Service (SMS), which is a tool used by utilities to balance actual throughput with supply.²⁶⁶ When a SOL is in place, MERC's typical five percent tolerance above the scheduled volume of SMS is not available. In other words, when a SOL is in effect, MERC has no tolerance available to be short on balancing gas supply deliveries against actual daily demand without being assessed significant imbalance penalties by NNG.²⁶⁷

²⁶² *Id.* at 23-24.

²⁶³ Ex. 101 at 25-28 (Smead Rebuttal).

²⁶⁴ *Id.* at 29-31.

²⁶⁵ Ex. 409 at 26 (Sexton Rebuttal).

²⁶⁶ Ex. 403 at 44 (Mead Direct); *see also* Ex. 803 at Sch. 11 (Cebulko Direct Schedules) (Response to Information Request CUB 39).

²⁶⁷ Ex. 403 at 44-45 (Mead Direct).

189. On Monday, February 8, MERC evaluated the weather for February 9 and beyond and identified that the weather was trending colder than normal for the next week. MERC called on its call options on February 8 for gas days February 9 and beyond.²⁶⁸ MERC continued to exercise this call option until February 18. MERC made no additional daily purchases for the February 9 gas day. At the end of the day of February 8, Gas Daily index prices settled at \$3.71 at Demarc and \$4.20 at Ventura for gas day February 9.²⁶⁹

190. On the morning of February 9, MERC again forecasted colder than normal weather and secured an additional 2,875 Dth/day at Gas Daily index prices. This purchase was agreed upon at 7:47 a.m. for the February 10 gas day only. At the end of the day on February 9, Gas Daily index prices settled at \$3.86 at Demarc and \$4.06 at Ventura for gas day February 10.²⁷⁰

191. On the morning of February 10, when forecasting for the February 11 gas day, MERC continued to see colder than normal weather forecasted. MERC forecasted for 248,375 Dth of system sales load for gas day February 11, after backing out forecasted transportation customer volumes (estimated to be 190,655 Dth). MERC met this forecasted load through storage withdrawals, baseload supplies, an Asset Management Agreement (AMA) call option, and 37,875 Dth of daily purchases. At the end of the day on February 10, daily prices on gas day February 11 settled at under \$7/Dth (\$6.61 at Demarc and \$6.91 at Ventura).²⁷¹

192. Because the daily gas market does not actively trade over weekends and holidays, MERC had to plan for its gas supply needs for the entire four-day holiday weekend, February 13-16, on or before February 12. Additionally, all call options and daily gas purchases over the four-day weekend had to be made ratably (i.e., in the same volume for each day of the four-day weekend). As a result, MERC planned for the highest forecast demand day and utilized storage to balance on the other three days. Because February 14 was the highest forecast demand day of the holiday weekend, MERC focused on that day.²⁷²

193. MERC started planning on the afternoon of February 11 for gas to be delivered starting on Saturday, February 13. MERC purchased daily gas on February 11 between 1:45 p.m. and 2:25 p.m. to ensure it could secure sufficient supply for customer demand. On the afternoon of February 11, when forecasting for the February 14 gas day (the highest demand day in the weekend), MERC continued to see colder than normal weather forecasted. Daily index prices at the end of the day on February 11 for gas day February 12 settled at \$15.68 at Demarc and \$15.42 at Ventura.²⁷³

²⁶⁸ *Id.* at 45. This call option was part of an AMA as detailed in Schedule 6 under the section labeled "Physical Forward Start (AMA) Exercised Trades" for the amount of 39,245 Dth/day. *Id.*

²⁶⁹ *Id.*

²⁷⁰ *Id.*

²⁷¹ *Id.* at 45-46.

²⁷² *Id.* at 46; see also Ex. 408 at 28-29 (Sexton Direct).

²⁷³ Ex. 403 at 46-47 (Mead Direct).

194. MERC was first notified on February 12, midmorning, that NNG had declared a Critical Day. A Critical Day is called when the operating condition of NNG's system has severely deteriorated and the integrity of the system is threatened.²⁷⁴

195. MERC's forecasted demand for gas day February 14 was 456,675 Dth for MERC-NNG system demand. Transportation customers were estimated at 187,789 Dth, making the total at the beginning of the planning period 268,886 Dth. MERC made a storage withdrawal from NNG storage of 87,341 Dth; however, based on fuel loss as dictated by NNG's FERC tariff, 86,302 Dth was planned for delivery to MERC's distribution system. MERC had monthly priced baseload gas purchases of 94,640 Dth, call options as part of an AMA of 38,779 Dth, and finally daily purchases of 56,832 Dth for a total flowing gas of 276,553 Dth, about 7,667 Dth or 1.68 percent long prior to the start of the gas day. At the end of the day February 12, index prices for the weekend (February 13-16) published at unprecedented levels – \$231.67 at Demarc and \$154.91 at Ventura.²⁷⁵

196. Throughout the next 40 hours, MERC continued to monitor the weather and review gas supplies for reliability. In addition, MERC evaluated the notices on the pipelines, fielded calls from suppliers, verified gas was scheduled correctly on the pipelines and from storage, and confirmed the overall volumes and processes. Around 7:00 a.m. on February 14, the forecast of gas load was reduced from 456,675 Dth to 379,990 Dth, and the transport customers' estimated volumes were reduced from 187,789 Dth to 137,765 Dth, or 50,024 Dth less than originally expected. MERC adjusted its storage withdrawal by 33,675 Dth to limit the daily imbalance on NNG. Once actuals were available, MERC's final forecast with all information now known, transport customers delivered 146,905 Dth or 40,884 Dth difference from the start of day planning period. The MERC-NNG system finalized the day with a 3.08 percent or 12,225 Dth long position.²⁷⁶

197. MERC started planning on the afternoon of February 15 for gas to be delivered starting on Wednesday, February 17. On the morning of February 16, when forecasting for the February 17 gas day, MERC continued to see colder than normal weather forecasted, but it was moderating. MERC purchased daily index priced gas on the morning of February 16 between 7:30 a.m. and 7:45 a.m. to ensure it was able to secure sufficient supply for customer demand.²⁷⁷

198. MERC's forecasted demand for gas day February 17 based on its raw load forecast was 391,379 Dth for the MERC-NNG system demand. Transportation customers were estimated at 138,405 Dth, making the total at the beginning of the planning period 252,974 Dth. MERC made a storage withdrawal from NNG storage of 87,341 Dth; however, based on fuel loss as dictated by NNG's FERC tariff, 86,302 Dth was expected for delivery to MERC's distribution system. MERC had monthly priced baseload gas purchases of 94,640 Dth, call options as part of an AMA of 38,779 Dth, and finally daily

²⁷⁴ *Id.* at 47.

²⁷⁵ *Id.*

²⁷⁶ *Id.* at 48.

²⁷⁷ *Id.*

purchases of 29,644 Dth for a total flowing gas of 249,365 Dth, about 3,609 Dth or 0.92 percent short prior to the start of the gas day.²⁷⁸

199. Throughout the next 20 hours, MERC continued to monitor the weather and review gas supplies for reliability. In addition, MERC evaluated the notices on the pipelines, fielded calls from suppliers, verified gas was scheduled correctly on the pipelines and from storage, and confirmed the overall volumes and processes. At the end of the day on February 16, gas daily index prices were published with a midpoint of \$133.64 at Demarc and \$188.32 at Ventura.²⁷⁹

200. On February 16 when planning for gas day February 17, MERC adjusted its raw load forecast for February 17 by reducing planned daily purchases by 27,188 Dth because it realized its forecast for gas deliveries was trending long over the previous few days. After this adjustment, MERC's adjusted load forecast for February 17 was 364,191 Dth.²⁸⁰

B. MERC Reliably Served Gas Customers During the February Event

201. On colder than normal days, such as those during the February Event, MERC proactively plans its natural gas supplies to ensure that it has sufficient supply to meet its customers' needs. MERC starts by forecasting its customer loads using the most recent weather forecast information and continuously, twice per day at a minimum, updates these load forecasts as the cold weather period approaches. Based on these customer load forecasts, MERC plans to procure sufficient amounts of gas, through either storage, baseload purchases, or daily market purchase, to ensure that it has adequate supply to meet its customers' needs and avoid extremely high pipeline penalties.²⁸¹

202. Natural gas commodity markets are not active during weekends and holidays. As a result, during a typical week, daily natural gas purchases for Saturday, Sunday, and Monday are made on Friday morning and must be made ratably (at the same quantity each day) over this period. In other words, the same volumes need to be purchased for each gas day within the period.²⁸²

203. Once MERC purchases gas supply for a day, MERC does not have the right to reduce its purchase quantity during the day of gas flow.²⁸³ The structure of the gas market does not typically allow for changes to purchased gas supply quantities during the flow day. Once a natural gas supply transaction is agreed upon, the purchase and sales quantity are in effect for the entire day of gas flow or on multiple days in the case of a weekend or holiday such as the four-day period during the February Event.²⁸⁴

²⁷⁸ *Id.* at 49.

²⁷⁹ *Id.*

²⁸⁰ Ex. 406 at 20 (Mead Rebuttal).

²⁸¹ Ex. 403 at 54-55 (Mead Direct).

²⁸² Ex. 408 at 27-28 (Sexton Direct).

²⁸³ *Id.* at 28. Although it is possible for a utility to sell gas back into the market, MERC has not regularly engaged in this practice. Ex. 506 at 61-62 (King Direct).

²⁸⁴ Ex. 408 at 28 (Sexton Direct).

204. Certain circumstances impacted MERC's planning and implementation of gas procurement during the February Event. From February 12-17, NNG had called a SOL with zero percent SMS. Additionally, from February 13-18, NNG called a Critical Day. For the Presidents' Day weekend, NNG also issued a warning that wellhead freeze-offs could occur. Freeze-offs occur when temperatures fall below freezing, resulting in water and other liquids contained in the natural gas mixture to freeze, blocking the flow of gas out of the wellhead. These conditions emphasized the importance for MERC to purchase sufficient gas supplies during the February Event to meet its customers' load.²⁸⁵

205. When a SOL is in place, MERC's typical five percent tolerance above the scheduled volume of SMS is not available. Therefore, when an SOL is in effect, MERC has no tolerance available to be short on balancing gas supply deliveries against actual daily demand without being assessed significant imbalance penalties by NNG. With the SOL notices that NNG declared, neither imbalance tolerance nor SMS were available, and MERC was left with no balancing services.²⁸⁶

206. A Critical Day is called when the operating condition of NNG's system has severely deteriorated and the integrity of the system is threatened. Usually, an SOL day will already be in effect prior to a Critical Day being called, but not always. A Critical Day may be called for all or part of the system by localizing the smallest affected area, beginning with individual points, followed by branch line, operational zone, market/field area, and up to the entire system, in that order.²⁸⁷

207. Because NNG declared a Critical Day on February 13, the potential risks became even higher because penalties of up to three times the daily spot price,²⁸⁸ or approximately \$695/Dth, would be assessed if the amount of gas that MERC took off the system did not match what it purchased.²⁸⁹

208. During the February Event, MERC had an obligation to provide continuous and reliable service to its firm customers and needed to purchase daily gas supplies in order to meet that obligation. MERC reviewed the latest available forecast along with the latest nominations made by transportation customers. The net difference represents the MERC requirements to serve system sales customers. MERC then planned for full delivery of the term baseload purchases and maximum storage withdrawals available. Due to a remaining need for gas, MERC executed all of its contracted call options and executed daily index purchases to ensure it had sufficient supply to meet the planning period needs.²⁹⁰

²⁸⁵ Ex. 403 at 50 (Mead Direct).

²⁸⁶ *Id.* at 51.

²⁸⁷ *Id.*

²⁸⁸ The imbalance penalty under these circumstances is up to three times the index price which for the Market Area is the highest published Platt's Gas Daily Midpoint price at NNG, Demarc or NNG, Ventura. *Id.* at 51 n.7.

²⁸⁹ *Id.* at 51; *see also* Ex. 408 at 29-30 (Sexton Direct). These imbalance penalties are set forth on NNG's Tariff Sheet No. 53 and the Daily Delivery Variance Charges (DDVC) rates page on NNG's website. Ex. 403 at 52 (Mead Direct).

²⁹⁰ *Id.* at 52-53.

209. MERC successfully arranged for sufficient natural gas supply to meet its customer needs during the February Event.²⁹¹

210. The Department, CUB, and the OAG do not dispute that the Gas Utilities provided reliable service to their customers during the February Event. They further maintain that reliability is not at issue in this proceeding, because this docket is directed to the issue of prudence related to the costs incurred. The Administrative Law Judges do not agree that reliability is not a consideration in this matter. The Gas Utilities incurred the extraordinary costs at issue in connection with their provision of reliable service, without experiencing customer shutoffs and all of the negative consequences that could have arisen if they did not procure sufficient gas during a tumultuous market event and during a weekend when Minnesota experienced cold weather. While reliability is not the central question of this proceeding, as it could be in the event the Gas Utilities had not procured sufficient gas to serve customers, reliability is integral to the understanding of this proceeding, and is not an afterthought.²⁹²

C. Disputed Issues Related to Load Forecasting and Curtailments During the February Event

211. The Commission's Order for Hearing directed development of the record as to any other issues or actions related to prudence that should be considered, and the potential financial impact of those issues.²⁹³ Two such issues have been developed related to MERC's extraordinary gas costs during the February Event: (1) MERC's load forecasting; and (2) curtailment of interruptible customers.

212. The Department and CUB allege that MERC's load forecasting for February 17 was unreasonably high or overly conservative and resulted in too much gas being procured for that day.²⁹⁴ Relatedly, CUB challenges MERC's storage optimization in light of its load forecasting recommendation.²⁹⁵

213. As to load forecasting, the Department and CUB recommend disallowances for February 17, though the two parties have identified different amounts that should be disallowed. CUB's ultimate recommended disallowance for load forecasting issues is \$3,903,233.²⁹⁶ The Department's recommended disallowance related to MERC's load forecasting on February 17 is \$9,707,206.²⁹⁷

²⁹¹ Ex. 408 at 6 (Sexton Direct).

²⁹² The Commission regulates public utilities "in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates." Minn. Stat. § 216B.01.

²⁹³ Order for Hearing at 23.

²⁹⁴ Ex. 401 at 5 (Eidukas Rebuttal).

²⁹⁵ Ex. 801 at 54 (Cebulko Direct).

²⁹⁶ Ex. 819 at 4 (Nelson Surrebuttal); Ex. 811 at 7 (Cebulko Surrebuttal).

²⁹⁷ Ex. 506 at 109 (King Direct); Ex. 507 at 53 (King Surrebuttal).

214. The Department and CUB also take the position that MERC's decision not to curtail its interruptible customers in response to market uncertainty and increasing prices was not reasonable.²⁹⁸

215. Regarding curtailments, the Department recommended a disallowance of \$958,307 based on the conclusion that MERC should have curtailed 50 percent of its available interruptible load on February 16 for Gas Day February 17, and reduced daily spot purchases accordingly.²⁹⁹ CUB recommended a disallowance of \$4,165,683 based on its position that MERC should have curtailed 50 percent of the interruptible load available on February 16 (the date with the most interruptible load available) over each day of the February Event.³⁰⁰

1. MERC's Load Forecasting and Supply Reserve Margin During the February Event

216. MERC evaluates its supply based on a range of factors, including monthly imbalance levels, pipeline constraints, storage inventory levels, and forecast uncertainty, including the duration of the forecast (i.e., a forecast covering a four-day weekend has more forecast uncertainty than a single-day forecast). Risk associated with supply cuts and production issues also impact the Company's planning for the appropriate level of supply reserve.³⁰¹

217. MERC contracts with DTN for actual and a 10-day weather forecast data, including Temperature, Normal Temperature, Dew Point, Humidity, Heat Index, Wind Chill, Wind Direction, Wind Speed, Wet Bulb, Cloud Cover, and Sunshine minutes. MERC also contracts with Marquette University to prepare gas day forecasts. Marquette University provides a forecasted average gas day temperature, average wind speed, and forecasted overall system load, inclusive of firm, interruptible, and transportation customers.³⁰² This information is then loaded into MERC's forecast planning system, which calculates heating degree days (HDD) that MERC uses for planning and monitoring the weather.³⁰³

218. MERC develops a raw load forecast based on the forecasted average temperature and wind speeds, day of the week, and historical actual load data. Customer usage patterns vary, for example, depending on whether it is a weekend or a weekday, and these variations are accounted for in the development of the forecasted load requirements.³⁰⁴

219. MERC also serves transportation customers who arrange for their own natural gas supply and interstate pipeline delivery. MERC forecasts its overall load

²⁹⁸ Ex. 401 at 5 (Eidukas Rebuttal).

²⁹⁹ Ex. 506 at 100, 109 (King Direct); Ex. 507 at 53 (King Surrebuttal).

³⁰⁰ Ex. 819 at 4 (Nelson Surrebuttal); Ex. 811 at 7 (Cebulko Surrebuttal).

³⁰¹ Ex. 406 at 28 (Mead Rebuttal).

³⁰² Ex. 406 at 14 (Mead Rebuttal).

³⁰³ Ex. 400 at 24 (Eidukas Direct).

³⁰⁴ Ex. 406 at 14-15 (Mead Rebuttal).

requirements for all customers and then removes the volumes transportation customers actually scheduled for delivery on the pipeline on the previous gas day to yield a system sales load forecast. That system sales load forecast forms the basis for MERC's gas supply decisions.³⁰⁵

220. MERC's normal practice is to begin the calculation of its load forecast on the business day before flow date; MERC's Gas Supply Group analyzes the forecast for accuracy based on previous days or previous similar weather prior to 7:30 a.m. The Gas Supply Group may adjust the raw forecast if that review results in a determination that the forecast is over- or under-stated relative to previous days, previous similar weather or similar market events, where the monthly imbalance is, pipeline conditions, exposure to penalties, and other relevant information.³⁰⁶

221. MERC's raw load forecast for the February Event is presented in the following table which reflects forecasted load before any adjustments were made for February 13-16, and for February 17.³⁰⁷

MERC's February Event Raw Load Forecasts

Gas Day	February 13	February 14	February 15	February 16	February 17
Raw Load Forecast	431,685	456,675	433,605	399,023	391,379
Scheduled Transport Volumes	187,789	187,789	187,789	187,789	138,405
System Requirements (forecast less known transport volumes)	256,570	243,896	245,816	211,234	252,974

222. For the Presidents' Day weekend, MERC was required to purchase gas ratably and take the same amount each day of the weekend. Therefore, MERC was required to purchase gas for each day of the weekend based on the day with the highest projected load, February 14.³⁰⁸

223. No party in this proceeding has recommended a disallowance for MERC's extraordinary gas costs for the February 13-16 period related to load forecasting.³⁰⁹ With respect to February 13-16, the Department did not take issue with MERC's load forecast, noting that because system-wide and transportation customer forecast both included the over-anticipation of transportation customer load compared to the load that was ultimately

³⁰⁵ *Id.* at 15.

³⁰⁶ *Id.*

³⁰⁷ *Id.* at 16.

³⁰⁸ Ex. 408 at 27-29 (Sexton Direct); Ex. 409 at 5-7 (Sexton Rebuttal); Ex. 506 at 25-26 (King Direct).

³⁰⁹ See Ex. 506 at 66-71 (King Direct); Ex. 811 at 20-21 (Cebulko Surrebuttal).

delivered, the net sales customer forecast is not necessarily impacted.³¹⁰ Further, in surrebuttal testimony, CUB witness Mr. Cebulko no longer recommended a disallowance for load forecasting related to February 13-16. Mr. Cebulko concluded that “MERC introduced new information that justifies its load forecast on February 14.”³¹¹

224. As February 14 was the coldest forecasted day of the Presidents’ Day weekend, MERC reasonably procured gas to ensure safe and reliable service to its customers based on its load forecast for February 14.³¹² MERC’s actions related to load forecasting for February 13-16, 2021, were prudent and reasonable and do not support a disallowance.

225. The Department and CUB challenge the prudence of MERC’s load forecasting for February 17, however, and recommend disallowances.³¹³ As a corollary to this issue, the Department contends that MERC used a supply reserve margin that was too high. The latter issue is addressed here first.

226. The Gas Utilities use various terminology to discuss their practice of purchasing additional gas supply, including supply reserve and being or buying slightly long.³¹⁴

227. During cold weather events, MERC typically targets being 20,000 to 25,000 Dth (about 7-9 percent of peak demand) long in order to avoid the risk of NNG’s escalated penalties and to ensure adequate supply of gas in light of other unknown variables, such as colder than forecasted temperatures and supply disruptions.³¹⁵

228. During the February Event, MERC considered additional variables related to developments over the weekend. Freeze-offs in the production wells started to occur, leading to reduced supply, just as demand across much of the U.S. spiked due to colder than normal temperatures.³¹⁶ Production losses were a significant issue at the time that MERC needed to purchase supply for February 17. Permian Basin production (which feeds Northern-Demarc) had suffered production losses of approximately 65 percent by the start of February 16 and the losses were still growing; those losses increased another 10 percent through February 16 and reached an unprecedented level of about 75 percent of Permian Basin natural gas production lost on February 17.³¹⁷

229. MERC took a conservative approach to planning for February 17 based on its knowledge that utilities were experiencing an unprecedented natural gas supply

³¹⁰ Ex. 406 at 16 (Mead Rebuttal); Ex. 506 at 69 (King Direct).

³¹¹ Ex. 811 at 18, 20-21 (Cebulko Surrebuttal).

³¹² Ex. 406 at 43 (Mead Rebuttal).

³¹³ Ex. 506 at 68-71 (King Direct); Ex. 801 at 39-41, 43-50, 59 (Cebulko Direct).

³¹⁴ See, e.g., Ex. 304 at 12 (Nieuwsma Rebuttal) (“supply reserve”); Ex. 409 at 9 (Sexton Rebuttal) (“supply reserves”); Ex. 121 at 26 (Grizzle Rebuttal) (“[I]f the Company is aware of the potential for supply cuts, we will purposefully try to be slightly long when we procure gas supplies. . . .”); Ex. 203 at Sch. 2 at 26 (Derryberry Direct) (“supply reserve (or safety margin)”).

³¹⁵ Ex. 406 at 28 (Mead Rebuttal).

³¹⁶ Ex. 403 at 58 (Mead Direct).

³¹⁷ Ex. 409 at 10-11 (Sexton Rebuttal); see also Ex. 100 at Sch. 5 (Smead Direct).

situation with significant, and growing, production losses, and uncertainty regarding weather forecasts and the accuracy and completeness of actual usage data, the continued risk associated with production freeze-offs, and the risk of supply cuts.³¹⁸ Under these conditions, MERC determined it should plan for a higher reserve margin for February 17.³¹⁹ For February 17, MERC planned to be about 23,000 Dth long, which means that MERC planned for a 10 percent supply reserve margin.³²⁰

230. MERC considered certain specific factors in planning for gas day February 17 including: (1) MERC does not own any peak shaving facilities to serve its Minnesota customers, which means that MERC does not have this tool to balance intraday load variability in the event the weather becomes colder than forecasted, customer load increases, or the Company experiences large supply cuts; and (2) MERC-NNG has access only to the NNG pipeline, and could not access other pipelines to mitigate any imbalances.³²¹

231. CUB does not take issue with MERC's use of a 10 percent reserve margin under the circumstances of the February Event. Mr. Cebulko, CUB's witness, noted: "MERC does not have peaking plants, nor does the Company have the same level of interruptible customers as CenterPoint or Xcel. I understand why, under these circumstances, a utility would create a relatively conservative supply margin."³²²

232. 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.³²³ Mr. King also noted that "[a]lthough large supply cuts did not manifest for February 14, natural gas production declines continued to increase."³²⁴

233. Even so, the Department argues that MERC should have used a supply reserve margin of two percent. The proposed two percent supply reserve margin is based on, but is slightly higher than, the actual supply reserve plans for the Four-Day Period as stated by CenterPoint (1.8 percent), MERC (1.7 percent), and Great Plains (1.8 percent).³²⁵

234. There are several problems with the Department's analysis. First, 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."³²⁶ Further, he testified that he was not

³¹⁸ Ex. 406 at 29 (Mead Rebuttal); Ex. 409 at 11-12 (Sexton Rebuttal).

³¹⁹ Ex. 406 at 29 (Mead Rebuttal).

³²⁰ *Id.* at 26, 29.

³²¹ *Id.* at 30-31.

³²² Ex. 811 at 22 (Cebulko Surrebuttal).

³²³ Ex. 506 at 56 (King Direct).

³²⁴ *Id.* at 65.

³²⁵ Ex. 507 at 34 (King Surrebuttal).

³²⁶ Evidentiary Hearing Tr. Vol. 2C at 50 (King).

recommending what a gas utility in Minnesota should use for a supply reserve margin on a permanent basis.³²⁷

235. 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.³²⁸

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

237. 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 for February 17. It also does not consider the information the Gas Utilities had in calculating a supply reserve margin for February 17, which included new knowledge of disruptions in the production of natural gas and ongoing supply issues; this knowledge was not available to the Gas Utilities when they made supply decisions for the four-day period in which they had lower reserve margins.

238. The Department asserts that a supply reserve margin should be deliberately determined and explainable.³²⁹ 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.³³⁰

239. The record reflects that MERC deliberately determined that it would approach supply decisions for February 17 from a conservative position because it was concerned about supply disruptions and its ability to obtain sufficient gas to serve its customers. During cold weather events, MERC typically targets being 20,000 to 25,000

³²⁷ *Id.* at 63.

³²⁸ *Id.* at 82.

³²⁹ Ex. 506 at 56 (King Direct); Ex. 507 at 32 (King Surrebuttal).

³³⁰ Evidentiary Hearing Tr. Vol. 2C at 80 (King).

Dth (about 7-9 percent of peak demand) long.³³¹ For February 17, MERC planned to be about 23,000 Dth long, which was within that range, and represented a 10 percent supply reserve margin for that day.³³²

240. The Administrative Law Judges determine that MERC's use of a 10 percent supply reserve margin for February 17 was reasonable and is supported by the record. Applying a two percent margin for February 17 retroactively to calculate a disallowance is not supported by the record.

241. Both the Department and CUB also contend that MERC erred in its load forecast for February 17, leading it to purchase excess gas.

242. The Department maintains that MERC-NNG's load forecast for February 17 was unreasonably high. Department witness Mr. King noted that while February 17 was the warmest day of the February Event, MERC-NNG's load forecast for its sales customers was the second highest after February 14.³³³ Mr. King opined that the forecasting error on February 17 occurred because MERC failed to account fully for the reductions in transportation load in its system-wide forecast.³³⁴ The Department contends that the method MERC uses to determine its sales forecast—subtracting a backwards-looking transport load (which for February 17 reflected the reduction in transportation load that manifested over the holiday weekend) from its forward-looking system-load forecast (which did not fully reflect the reduction in transportation load)—inflated the sales-customer forecast amount, causing MERC to forecast that its sales customers would use 20 percent more gas on February 17 than on February 16.³³⁵ The Department recommended a disallowance based on the difference between the forecasted transportation load over the four-day weekend February 13-16 and the forecasted transportation load on February 17,³³⁶ in the amount of \$9,707,206.³³⁷

243. CUB opined MERC had “overly conservative” load forecasts, which led to the over-procurement of gas.³³⁸ CUB maintained in surrebuttal testimony that MERC had not adequately addressed its concerns regarding load forecasting for February 17.³³⁹ Mr. Cebulko concluded in surrebuttal that “[a]lthough MERC's forecasting error on February 17 is lower than it appeared in direct testimony, given the revised figures introduced in the Company's rebuttal testimony, MERC's forecasting error for Sales

³³¹ Ex. 406 at 28-29 (Mead Rebuttal).

³³² *Id.* at 26, 29.

³³³ Ex. 506 at 68 (King Direct).

³³⁴ Ex. 507 at 46-48 (King Surrebuttal).

³³⁵ Department's Reply Br. at 21-22 (Mar. 25, 2022) (eDocket No. 20223-184159-08). Because this error was an unreasonable mistake from a mathematical perspective, the Department recommended disallowing the full amount of the error. *Id.*

³³⁶ Ex. 506 at Sch. 3 at 1 (King Direct).

³³⁷ Ex. 507 at 53 (King Surrebuttal).

³³⁸ Ex. 801 at 32-50 (Cebulko Direct).

³³⁹ Ex. 811 at 22 (Cebulko Surrebuttal).

customers on February 17 remains quite high: 14 percent.”³⁴⁰ CUB recommended a disallowance of \$3,903,233 based on a 5 percent forecasting error.³⁴¹

244. MERC’s load forecast of 391,379 for February 17 is in line with actual load experienced under similar weather and during a weekday period. But on February 16, as MERC planned purchases for February 17, MERC realized the prior few days’ forecasts trended to be over forecasted. MERC adjusted its estimates and reduced the daily purchases from the previous days by 27,188 Dth, or from 56,832 to 29,644 Dth, for spot purchases.³⁴² Due to this reduction, MERC’s adjusted load forecast for February 17 was 364,191 Dth.³⁴³

245. MERC witness Sarah Mead testified that MERC’s experience in recent history with similar weather and day of the week resulted in actual customer loads ranging from about 348,000 Dth to 382,000 Dth.³⁴⁴

246. Specifically, for 13 mid-week days since December 2019 with similar average temperatures as February 17, the historical actuals varied between 348,018 Dth to 382,727 Dth, with an average of 361,706 Dth. Prior to being adjusted downward for actual daily gas purchases, the raw forecasted data for February 17 (391,379 Dth) was only 8,652 Dth higher than the historical actuals with a similar average temperature and day of week that occurred on December 11, 2019.³⁴⁵

247. The table below shows the high, low, and average forecasts available at the time decisions were made for February 17 gas purchases. Because MERC was aware that the raw forecast was not the best forecast to plan to, MERC targeted between the highest historical actual day and the lowest historical actual day, settling around the average historical days and going into the day with planned supply approximately 10 percent above adjusted forecasted load as a supply reserve margin.³⁴⁶

³⁴⁰ *Id.*

³⁴¹ *Id.* at 7; Ex. 819 at 4 (Nelson Surrebuttal).

³⁴² Ex. 406 at 24 (Mead Rebuttal).

³⁴³ *Id.* at 20.

³⁴⁴ *Id.* at 29.

³⁴⁵ *Id.* at 23.

³⁴⁶ *Id.* at 25-26.

High, Low, and Average Load Range

Day of Gas Flow	Wednesday 2/17/2021	Wednesday 2/17/2021	Wednesday 2/17/2021	Wednesday 2/17/2021	Wednesday 2/17/2021
	Original filed	Lowest	Highest	Average	Final Adjusted
Gas Purchase Process Based upon Information Known at time of Final Spot Gas Purchase Day for Flow Day					
Forecast For Day of Gas Deliveries	391,379	348,018	382,727	361,706	364,191
Latest Transportation Customer Info Known at Time of Purchase	(138,405)	(138,405)	(138,405)	(138,405)	(138,405)
System Requirements (Forecast less known Transport)	252,974	209,613	244,322	223,301	225,786
	252,974	209,613	244,322	223,301	225,786
Start of Day Storage Nominations	87,341	87,341	87,341	87,341	87,341
Delivered Storage per Start of Day Nominations	86,302	86,302	86,302	86,302	86,302
Planned Delivered Supplies (Ignores Cuts)					
Term Baseload	94,640	94,640	94,640	94,640	94,640
Physical Forward Option	38,779	38,779	38,779	38,779	38,779
Spot Purchase	29,644	29,644	29,644	29,644	29,644
Planned Purchases/ Withdrawals - Long/(Short) vs Forecast	(3,609)	39,752	5,043	26,064	23,579
Reserve Delivered Supply (%)	-1.43%	18.96%	2.06%	11.67%	10.44%

248. As shown in the next table, MERC's actual total load on gas day February 17 was lower than the Company's total load forecast by approximately 12 percent. MERC contends that the variance resulted from several factors, including that the weather was warmer than forecasted and transportation customers used less than they scheduled on the pipeline to have delivered into MERC's distribution system.³⁴⁷

Actual Load Results for Gas Day February 17

Gas Day 2/17/2021	Formula	Total (Dth)	Transport (Dth)	Sales (Dth)
A. Forecast when Planning	"Total" = Raw Forecast (391,379) w/ Adjustment (27,188)	364,191	138,405	225,786
B. Actual Load		325,439	126,790	198,649
C. Imbalance	A-B	38,752	11,615	27,137
D. % Imbalance of Customer Type (Actuals)	(A-B)/B	12%	9%	14%
E. % Imbalance of Total (Actuals)	(A-B)/B	12%	4%	8%

³⁴⁷ *Id.* at 31.

249. The “Total” column (which uses the adjusted forecast) shows the actual load at the end of the day and the imbalance as an over-delivery of about 38,000 Dth, or 12 percent, for February 17.³⁴⁸

250. MERC-NNG’s adjusted daily load forecast of 364,191 Dth for February 17 was 12 percent over its actual daily load of 325,439 Dth.³⁴⁹ But MERC’s forecast was consistent with historic actual load under similar weather conditions.³⁵⁰ MERC’s adjusted February 17 daily load forecast of 364,191 was less than one percent higher than the average daily load of 361,706 Dth over all Tuesdays and Wednesdays in January through March of 2019, 2020, and 2021 with similar temperatures.³⁵¹ MERC’s actual daily load for February 17 was more than 22,500 Dth lower than the next highest MERC-NNG actual daily load under similar weather occurring on either a Tuesday or Wednesday in 2019, 2020, and 2021. MERC-NNG’s actual daily load for February 17, 2021, was more than 36,200 Dth lower than the average daily load over these same timeframes.³⁵²

251. MERC’s transport customers contributed a significant portion of the total imbalance for February 17. Of the total MERC imbalance of about 38,000 Dth, transportation customers directly caused about 11,000 Dth or about 30 percent of MERC’s daily imbalances on the interstate pipeline. Sales customers contributed about 27,000 Dth to the total imbalance.³⁵³

252. MERC has little control of transportation customer imbalances. MERC’s transportation tariff (Tariff sheet 6.03) has a monthly cashout procedure that financially settles the monthly net imbalance at the end of each month. However, MERC does not have control over daily load issues with respect to transportation customers. MERC does know what the transportation customers’ usage will be each day, beyond customer nominations, and it cannot assume that transportation customers will over-deliver, even if they are incentivized to balance supplies to avoid punitive penalties during critical days.³⁵⁴

253. The Department contends that MERC has provided only system-wide historical data and has not offered information comparing its historic sales customer load to its amount of gas it purchased to serve sales customers on February 17. The Department also contends MERC failed to properly account for a dwindling transportation load in its forecasting.³⁵⁵ The question presented in this matter is whether MERC acted prudently based on the information it had at the time it made decisions. Load forecasting is not a science and it is not possible to forecast with exact precision; with regard to transportation customer load, MERC used information from the day before, which was the most recent information available. Further, even if some variability existed between

³⁴⁸ *Id.* at 32.

³⁴⁹ *Id.*

³⁵⁰ *Id.* at 24.

³⁵¹ *See id.* at 23.

³⁵² *See id.*

³⁵³ *Id.* at 32-33.

³⁵⁴ *Id.* at 33-34.

³⁵⁵ Department’s Reply Br. at 21-22 (Mar. 25, 2022) (eDocket No. 20223-184159-08).

MERC's historical figures and its forecast and actuals for February 17, that would not establish MERC was imprudent.

254. Additionally, actual temperatures for February 17 were warmer across all four of the weather stations used to forecast load for MERC-NNG, as shown below.³⁵⁶ All else equal, warmer than forecasted temperatures will result in actual load below forecast.³⁵⁷

Actual Average Daily Temperatures – Gas Day February 17

Weather Station	Forecasted Average Daily Temperature (Feb. 17)
Minneapolis International	7.7 degrees Fahrenheit (1.4 degrees warmer)
Rochester	4.8 degrees Fahrenheit (0.7 degrees warmer)
Cloquet	6.8 degrees Fahrenheit (6.1 degrees warmer)
Worthington	5.3 degrees Fahrenheit (0.3 degrees warmer)

255. The Department argues that MERC has failed to provide a quantification of the impact of a degree or fraction of a degree in temperature in its service area impacts its customer load.³⁵⁸ But this issue is really addressed to the actual load MERC experienced on February 17, not to its forecast, as it could not predict exactly where temperatures would settle out. The actual load, and the difference in calculation degree by degree, is not at issue.

256. CUB contends that that MERC's load forecast, when coupled with its 10 percent supply margin, was unreasonable, given that MERC was aware by February 16 that spot market prices were extraordinarily expensive.³⁵⁹ CUB witness, Mr. Cebulko, testified that MERC's forecasted load exceeded actual demand by over 10 percent on only one occasion throughout January and February of 2018-2020, and had never exceeded 12 percent.³⁶⁰ Yet, he also notes that it would be unreasonable to expect a utility to forecast load perfectly,³⁶¹ and he acknowledged that MERC had *under-*forecasted load by over 10 percent on additional occasions.³⁶²

257. CUB maintains that, under the circumstances presented for February 17, "a reasonable utility would have more carefully balanced the real, readily apparent risk of

³⁵⁶ Ex. 406 at 22 (Mead Rebuttal).

³⁵⁷ *Id.*

³⁵⁸ Department's Reply Br. at 23 (Mar. 25, 2022) (eDocket No. 20223-184159-08).

³⁵⁹ CUB Reply Brief at 7 (Mar. 25, 2022) (eDocket No. 20223-184162-06).

³⁶⁰ Ex. 811 at 22 (Cebulko Surrebuttal).

³⁶¹ Ex. 801 at 47 (Cebulko Direct).

³⁶² Evidentiary Hearing Tr. Vol. 3 at 110 (Cebulko).

financial harm to MERC's customers associated with the spot market prices against the warranted, but still speculative, concerns about potential supply disruptions or potential pipeline imbalance penalties."³⁶³ There are several problems with this approach. First, CUB acknowledges that MERC's concerns about obtaining adequate supply were warranted, and simultaneously dismisses them as speculative. Second, CUB does not adequately consider the very real possibility that a pipeline imbalance could have led to gas prices of up to three times the amount that MERC actually incurred, and that MERC sought to ensure it had sufficient gas to avoid this even greater financial injury to its customers. Finally, MERC's foremost priority over the February Event was reliably serving its customers during a period of cold temperatures during the peak heating season; pricing concerns, while very important, do not shift this fundamental prioritization.

258. MERC's load forecast procurement practices related to February 17 were prudent and reasonable under the circumstances. The Administrative Law Judges do not recommend a disallowance related to load forecasting on February 17.

2. Curtailment During the February Event

259. Both Department and CUB recommended disallowances because MERC did not plan to curtail interruptible load during the February Event.³⁶⁴

260. The Department maintains that it was reasonable that MERC did not call curtailments for February 13 through 16.³⁶⁵ The Department's witness, Mr. King, acknowledged that "[t]he traditional use of curtailment is for capacity-related needs when pipeline availability is fully utilized," and that "[c]alling curtailment based on economics due to a spot gas price spike is outside of how the Gas Utilities plan on and have historically used curtailments."³⁶⁶ Further, Mr. King acknowledged that the magnitude of the price spike was unprecedented and not fully understood on February 12 when MERC had to make its purchasing decisions for the four-day weekend.³⁶⁷

261. However, the Department contends that MERC should have planned on February 16 to curtail interruptible customer load, thereby reducing its need for spot purchases made on February 16 for February 17. Department witness Mr. King testified that "[e]ven though outside of planned and historical usage, the Gas Utilities should have planned to curtail on February 17 in light of the extraordinary price spike."³⁶⁸

262. The Department recommended a disallowance for MERC of \$958,307, based on an assumed volume of planned curtailments equal to 50 percent of the usage of curtailment customers on February 17.³⁶⁹

³⁶³ CUB Reply Brief at 7 (Mar. 25, 2022) (eDocket No. 20223-184162-06).

³⁶⁴ Ex. 506 at 100-01, 109 (King Direct); Ex. 507 at 53 (King Surrebuttal); Ex. 811 at 7 (Cebulko Surrebuttal).

³⁶⁵ Ex. 506 at 98-99 (King Direct).

³⁶⁶ *Id.* at 99.

³⁶⁷ *Id.*; *see also* Ex. 401 at 21-22 (Eidukas Rebuttal).

³⁶⁸ Ex. 506 at 100 (King Direct).

³⁶⁹ *Id.* at 100-01; *see also* Ex. 401 at 22-23 (Eidukas Rebuttal).

263. CUB's witness, Mr. Cebulko, concluded that based on prices for gas on February 11, pipeline warnings, and uncertainty going into the four-day weekend, MERC should have "locked in the benefit to the system and customers by curtailing interruptible customers."³⁷⁰ Mr. Cebulko also opined that MERC's decision not to curtail customers on February 17 was unreasonable in light of the fact that the settled price of natural gas was greater than \$150/Dth.³⁷¹

264. CUB calculated a range of a potential disallowance starting at \$902,791 on the basis that MERC did not curtail 50 percent of its interruptible load on February 17, to a disallowance of \$4,165,683 for MERC's not curtailing interruptible load for February 13 through 17.³⁷² The high end of CUB's range is based on an assumption that MERC could have "curtailed 50% of the interruptible load available on February 16 [the date with the most interruptible load available] over each day of the weekend to comply with the requirement for ratable spot purchases."³⁷³ Mr. Nelson opined that MERC should have curtailed interruptible customers on all five days resulting in a disallowance at the high end of the range.³⁷⁴ CUB's eventual recommended disallowance is \$4,165,683.³⁷⁵

265. MERC contends that: (1) its tariffs do not provide for price-based curtailment; (2) price-based curtailments would be contrary to its Commission-approved interruptible rate structure; (3) MERC has not previously curtailed interruptible customers based on the price of natural gas and while such events have been the subject of Commission review and investigation, neither the Commission nor any other party has urged the adoption of economic-based curtailments; (4) MERC had no knowledge when it purchased gas for the four-day weekend that prices would spike to unprecedented levels.³⁷⁶

266. None of MERC's customers were interrupted during the February Event. MERC did not experience distribution system issues or issues with adequate pipeline capacity or constraints that would have required interruption of customers for operational or supply reasons. MERC's system performed as expected, and MERC had adequate pipeline capacity to meet customer demand with no interruptions to customers.³⁷⁷

267. Interruptible customers reduce overall pipeline capacity costs and distribution system fixed costs for the benefit of all of MERC's general service customers, while ensuring MERC can provide continuous and reliable natural gas service to firm customers in the event of a design day. MERC plans its pipeline capacity and sizes the distribution system only to meet firm customer load requirements in the event of design

³⁷⁰ Ex. 801 at 71 (Cebulko Direct).

³⁷¹ *Id.* at 72.

³⁷² Ex. 811 at 7 (Cebulko Surrebuttal).

³⁷³ Ex. 801 at 76 (Cebulko Direct).

³⁷⁴ Ex. 810 at 10 (Nelson Direct).

³⁷⁵ Ex. 811 at 7 (Cebulko Surrebuttal); Ex. 819 at 4 (Nelson Surrebuttal).

³⁷⁶ Ex. 401 at 25-26 (Eidukas Rebuttal).

³⁷⁷ *Id.* at 27-28.

day conditions. Under such conditions, interruptible customers will be subject to curtailment so that MERC can provide continuous reliable service to its firm customers.³⁷⁸

268. In exchange for agreeing to curtail, interruptible customers pay a lower rate for interruptible distribution service than they otherwise would for firm distribution service.³⁷⁹ MERC's interruptible rates are calculated to reflect the risk associated with interruptible customers being called upon to curtail their natural gas usage in the event of inadequate interstate pipeline capacity or a distribution system constraint or issue.³⁸⁰

269. In MERC's last general rate case, in Docket No. G011/GR-17-564, MERC narrowed the differential between firm and interruptible distribution rates to recognize the reduced risk of interruption following the addition of its Rochester pipeline capacity. The Commission approved final rates with a reduction in the differential between firm and interruptible rates, to reflect the reduction in the risk of curtailment resulting from MERC's increasing its interstate pipeline capacity.³⁸¹

270. MERC's tariffs provide the following definition of "Interruptible Service":

Customers taking natural gas service which may be interrupted, curtailed or discontinued at any time at the option of the Company in accordance with the provisions herein. All interruptible customers must either (1) have and maintain adequate standby facilities and have available sufficient fuel supplies to maintain operations during periods of curtailment or (2) have the ability to fully and completely suspend the use of interruptible gas on one hour's notice when requested to do so by the Company.³⁸²

271. MERC's Interruptible Service Tariff states: "Customers under this rate schedule are subject to interruption at any time upon order of MERC" and goes on to state the customers' requirements for maintaining standby service, the requirements for transferring from firm to interruptible service, and the penalty for unauthorized use while service is interrupted.³⁸³ MERC's interruptible tariff also cross-references the General Terms and Conditions.

272. MERC's tariff establishes the priority for which customers will be cut off as follows:

³⁷⁸ *Id.* at 28.

³⁷⁹ *Id.*

³⁸⁰ *Id.* at 30.

³⁸¹ *Id.* at 30-31.

³⁸² General Rules, Regulations, Terms and Conditions, 3rd Revised Sheet 8.01, *available at* <https://www.minnesotaenergyresources.com/company/tariffs/rules.pdf>. The tariff defines "Firm Service" as "Service supplied to customers under schedules or contracts which are not normally subject to curtailment or interruption except under occasional, extraordinary circumstances." *Id.* at 8.03.

³⁸³ Rate Schedule NNG Interruptible Service, 9th Revised Sheet No. 5.10, *available at* <https://www.minnesotaenergyresources.com/company/tariffs/iss.pdf>.

Priority of Service

Company will make every reasonable attempt to maintain continuous gas service to firm service customers. Interruptible customers are subject to curtailment. The following priorities will be followed when operational and supply conditions require service interruptions with highest priorities listed first:

1. Residential Sales/Farm Tap Residential
2. Commercial & Industrial Firm Class 1 / Farm Tap Firm Class 1
- ...
9. Firm/Interruptible Service Customers' Firm Nominations
10. Commercial and Industrial Interruptible Class 1
- ...
16. Power Generating Unit Class 1
17. Power Generating Unit Class 2
18. Agricultural Grain Dryer Class 1
-³⁸⁴

273. MERC contends that it was not permitted to curtail interruptible customers for economic reasons, but rather that it could curtail when it became necessary because it could not obtain adequate supply, or for operational reasons related to the delivery of gas.³⁸⁵ MERC contends that, within the utility industry, the term “supply conditions” in the context of customer curtailments refers to conditions under which the utility has inadequate supply or is unable to deliver supply to customers, it does not relate to pricing.³⁸⁶ It further argues that, if such curtailments could be called, its existing rate structure and differential between firm and interruptible service would need to be reevaluated in a rate case or other proceeding and implemented only on a forward-looking basis.³⁸⁷

274. During the February Event, MERC evaluated the pipeline capacity it holds each day to determine if the capacity was adequate to supply the forecasted load. MERC also analyzed any distribution system constraints or operational issues. MERC determined that adequate pipeline capacity and natural gas were available to supply MERC's system sales customers, so MERC did not interrupt customers during the four-day period from Saturday, February 13, 2021, through Tuesday, February 16, 2021.³⁸⁸

³⁸⁴ General Rules, Regulations, Terms and Conditions, 3rd Revised Sheet 8.40a, *available at* <https://www.minnesotaenergyresources.com/company/tariffs/rules.pdf>.

³⁸⁵ Ex. 400 at 28 (Eidukas Direct).

³⁸⁶ Ex. 401 at 32-33 (Eidukas Rebuttal).

³⁸⁷ *Id.* at 30; *see also* Ex. 506 at 99 (King Direct).

³⁸⁸ Ex. 400 at 27-28 (Eidukas Direct).

275. MERC reviewed its tariffs and determined that MERC could not curtail interruptible customers based only on high prices, and its historic practice is consistent with this judgment.³⁸⁹

276. CUB argues that MERC's tariff allowed it to curtail interruptible customers "at any time at the option of the Company." CUB further argues that MERC's tariffs do not expressly allow, or prohibit, curtailments for economic reasons, and that the tariff does not define "operational and supply conditions" that trigger the prioritization of service. CUB posits that, due to the high price of gas during the February Event and uncertainty about possible supply cuts during the event, MERC should have curtailed.³⁹⁰

277. CUB's argument is flawed. CUB's position rests on a reading of the tariff that ignores limiting language stating that MERC may curtail customers at any time and at the option of the company "in accordance with the provisions herein."³⁹¹ MERC does not have unfettered discretion to use its pool of interruptible customers as a price protection mechanism. Further, the tariff establishes a priority of service "when operational and supply conditions require service interruptions."³⁹² Reading the document consistent with CUB's interpretation requires determining that a priority system exists for curtailments for operational or supply reasons, but that there is no specific priority of service when curtailments are called for other reasons.

278. To adopt CUB's position, the Commission would be required to hold that MERC was required to curtail interruptible customers in order to be considered to have acted prudently, when MERC's tariff makes no mention of economic curtailment, contains no terms indicating when such a curtailment may be triggered, and does not establish a priority of service in such an event, MERC has never engaged in such curtailments in the past, and the Commission did not indicate prior to the February Event that economic curtailments can or should be undertaken by MERC in the event of high gas prices. This is not a reasonable position.

279. The Department's argument fares similarly. The Department does not contend MERC should have curtailed prior to February 16, because the extent of the increase in gas prices was not known when MERC initially purchased gas for the four-day weekend. It argues, that by February 16, when MERC purchased gas for February 17, it knew that prices had increased to extremely high levels and that production failures were continuing. While MERC had not historically curtailed based on price, the Department argues that MERC should have taken unprecedented steps to deal with those unprecedented prices.³⁹³

³⁸⁹ Ex. 401 at 34 (Eidukas Rebuttal).

³⁹⁰ See CUB Reply Brief at 9-10 (Mar. 25, 2022) (eDocket No. 20223-184162-06).

³⁹¹ General Rules, Regulations, Terms and Conditions, 3rd Revised Sheet 8.01, *available at* <https://www.minnesotaenergyresources.com/company/tariffs/rules.pdf>.

³⁹² General Rules, Regulations, Terms and Conditions, 3rd Revised Sheet 8.40a, *available at* <https://www.minnesotaenergyresources.com/company/tariffs/rules.pdf>.

³⁹³ Ex. 507 at 6 (King Surrebuttal).

280. While the Department has recommended a more limited disallowance based on these arguments, its position still relies on a determination that MERC could have curtailed interruptible customers based on gas prices when it had never done so before, and its tariff contained no terms governing such a curtailment or indicating when it might be called.

281. MERC's tariff does not contemplate curtailment of interruptible customers based on the price of gas, and in the absence of any supply or operational system constraints. Therefore, MERC did not act imprudently when it did not curtail customers during the February Event. Therefore, no disallowance on this basis is warranted.

282. The Commission may wish to consider whether price-based curtailments are a reasonable mechanism to use in the event of a price spike event in the future, and to establish parameters governing the terms of such a curtailment and require appropriate revisions to MERC's tariff. At the time of the February Event, these provisions were not in place.

D. MERC's Usage of Storage During the February Event

283. The Commission's Order for Hearing directed consideration as to whether the Gas Utilities maximized their use of storage capacity during the February Event.³⁹⁴

1. Overview of Storage Contracts and Planning

284. Natural gas storage provides MERC's primary means of balancing supply and demand day-to-day through nominations. Storage is imperative to maintain system integrity and to respond to weather pattern changes. In addition, customer consumption fluctuations may affect MERC's ability to meet customer demand. MERC utilizes storage to provide natural gas deliverability during periods of high demand and for operational flexibility in balancing the system.³⁹⁵ NNG storage allows for a nomination to be made utilizing MERC's NNG storage prior to 8 a.m. or when about 23 hours of the gas day³⁹⁶ have passed. This provides MERC with operational flexibility to manage the daily, as well as cumulative monthly, imbalances it has with NNG.³⁹⁷

285. In addition to operational benefits, storage provides a physical price hedge for customers by reducing the amount of gas purchased in the winter and increasing the amount purchased in the summer for delivery at a later date.³⁹⁸

286. Department witness Mr. King agreed: "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. Storage is a very

³⁹⁴ Order for Hearing at 22.

³⁹⁵ Ex. 400 at 23 (Mead Direct).

³⁹⁶ A "gas day" is defined as the 24-hour period from 9 a.m. Central Clock time to 9 a.m. Central Clock time. *Id.* at 27 n.3.

³⁹⁷ *Id.* at 26-27; see also Ex. 408 at 31 (Sexton Direct).

³⁹⁸ Ex. 403 at 23 (Mead Direct).

valuable asset, an important operational tool, and all the Gas Utilities hold contracts for storage.”³⁹⁹

287. For the most part, storage costs are controlled by long-term service agreements with pipelines. Gas prices associated with storage do not react to changing market conditions as rapidly as gas commodity prices react. During the winter season (November 2020 through March 2021), MERC utilized a 40 percent/30 percent/30 percent strategy to mitigate price volatility and provide reasonably priced natural gas. The strategy consists of 40 percent of normal winter supply requirements purchased at a FOM index price, 30 percent supplied by physical storage, and 30 percent covered by financial hedges (10 percent futures and 20 percent call options). Storage supply and financial products were purchased from May through October 2020. This approach provided MERC customers with 60 percent of the portfolio protected from increasing market prices via storage, call options, and futures.⁴⁰⁰

288. MERC has contracted pipeline storage contracts with ANR and NNG. The ANR storage is only deliverable to the MERC-Consolidated system customers, while the NNG storage is only deliverable to customers served by the MERC-NNG system. MERC’s storage contracts specify a maximum storage volume and set forth contractual requirements related to the injection and withdrawal of natural gas from storage throughout the year.⁴⁰¹

289. To meet its customers’ forecasted needs, MERC regularly evaluates its existing storage situation to understand what storage options are available and to evaluate the best use of available storage based on information known at the time. MERC’s evaluation considers: (1) the withdrawal capability available; (2) MERC’s total storage balance; (3) the amount of storage gas needed to meet customer needs for the remainder of the winter season; (4) what options are available; and (5) the best use for the asset based on the information available. During extremely cold periods—including the February Event—MERC maximizes its storage withdrawal limits to the fullest extent allowed by its contracts, especially later in the winter, as less storage is needed to meet customer needs for the remainder of the winter.⁴⁰²

290. MERC must utilize contracted pipeline capacity to deliver withdrawn storage supplies to customers on the MERC-Consolidated and MERC-NNG systems.⁴⁰³

291. MERC’s total NNG storage capacity for the 2020-2021 winter heating season was 6,519,321 Dth with a maximum daily withdrawal of capability prior to ratchets

³⁹⁹ Ex. 506 at 21 (King Direct).

⁴⁰⁰ Ex. 403 at 23-24 (Mead Direct).

⁴⁰¹ *Id.* at 24 (Mead Direct). The Commission approved MERC’s ANR Storage contract on January 8, 2018, in MPUC Docket No. G011/M-17-587. *Id.* at 25.

⁴⁰² *Id.* at 55.

⁴⁰³ *Id.* at 24.

of 104,402 Dth. Based on this, MERC's NNG storage accounted for 29 percent of the MERC-NNG forecasted normal winter demand for the 2020-2021 heating season.⁴⁰⁴

292. Each day, MERC performs a final forecast by reviewing estimated throughput available for the first 20 plus hours of the gas day as well as the latest scheduled volumes made by MERC's transportation customers. MERC also requests that transportation customers communicate any nomination changes they plan to make for the 23rd hour nomination cycle. With the latest forecast and transportation nominations, MERC can adjust its storage nominations to minimize any daily imbalances. Minimizing daily imbalances lowers the costs associated with daily imbalances and also minimizes the costs associated with the cumulative monthly imbalance. This approach also allows MERC to retain gas in storage for use on the remaining days within the month instead of having those volumes in an inaccessible imbalance account.⁴⁰⁵

293. MERC determines supply requirements for MERC customers on a daily and monthly basis. On a monthly basis, MERC's policy is to purchase and schedule the required flowing natural gas supply and required storage injections or withdrawals based upon the forecast monthly requirements, taking into account applicable contract requirements.⁴⁰⁶

294. On a daily basis, MERC's policy is to purchase and schedule additional flowing gas supply and storage injections or withdrawals based upon changes from the monthly plan. In the event additional market supply is necessary, MERC considers the most economic and operationally efficient option available in deciding whether to purchase supply in the market, decrease injections, or increase storage withdrawals.⁴⁰⁷

2. Use of Storage Capacity During the February Event

295. During the February Event, MERC's Maximum Daily Withdrawal Quantity (MDWQ) was 87,341 Dth/day.⁴⁰⁸

296. After deploying maximum storage withdrawals, MERC seeks to meet the remainder of its forecasted customer demand by calling on prearranged purchase agreements and then, as a last resort, purchasing gas in the daily market.⁴⁰⁹

297. During the February Event, there was a holiday on Monday, which required MERC to make purchase decisions by the morning of Friday, February 12 for gas deliveries for the four-day period from Saturday, February 13 through Tuesday,

⁴⁰⁴ *Id.* at 26. MERC has sought opportunities over the years to increase its available storage capacity and, effective June 1, 2017, acquired 1,500,000 Dth of released storage on NNG, which was approved by the Commission on December 6, 2017, in MPUC Docket No. G011/M-16-650. This contract was permanently released to MERC in January 2021 and was renegotiated with a new expiration of May 31, 2026.

⁴⁰⁵ *Id.* at 27; see also Ex. 408 at 31 (Sexton Direct).

⁴⁰⁶ Ex. 403 at 27-28 (Mead Direct).

⁴⁰⁷ *Id.* at 28.

⁴⁰⁸ Ex. 408 at 24 (Sexton Direct).

⁴⁰⁹ Ex. 403 at 55-56 (Mead Direct).

February 16.⁴¹⁰ Because purchases over the four-day weekend were required to be ratable (i.e., the same volume of gas must be purchased each day of the four-day weekend),⁴¹¹ MERC planned its gas purchases to meet the highest daily load forecast by setting daily purchases for the weekend based off this day. While the forecasted demand was not the same on all four days (due to forecasted warmer and colder days over this period), because natural gas had to be traded in equal increments for all four days, MERC was required to purchase more than what it forecasted for three of the four days during the weekend.⁴¹²

298. After MERC had completed its daily market purchases, MERC monitored its supply position throughout each day. In doing so, MERC waits until the final cycle on NNG, which is due at 8:00 a.m. (one hour prior to the end of the gas day), before it does its final balancing. MERC reviewed the available information at that time and determined what, if any, adjustments to make. At this point, the only supply that MERC is able to adjust is storage withdrawals because MERC had already made its daily market purchases. MERC reduced these withdrawals to closely match the total actual flows to customers.⁴¹³

299. MERC does a final review of its supply and compares it to the forecasted demand just prior to this deadline. At that time, transportation customers have made more accurate nominations, and the forecasted demand typically is much closer to the final actual expected throughput. If there is a large enough difference between the supply and forecasted demand, MERC will adjust the storage withdrawal nominations to be much closer to the latest forecasted system requirements. In situations like the February Event, MERC targets being long to reduce the risk of NNG's penalties.⁴¹⁴

300. MERC nominated all of its storage withdrawal rights when executing its day ahead process (87,341 Dth/day each day of February Event). MERC continued to nominate all of its storage withdrawal rights throughout the day, evening, and night right up until the next morning or the 23rd hour nomination for NNG storage. NNG allows for nomination changes up until 8:00 a.m. on the gas day or after about 23 hours have passed in the gas day.⁴¹⁵

301. Department witness Mr. King did not recommend any disallowance of costs associated with MERC's use of storage.⁴¹⁶

302. CUB disputed MERC's use of storage only in relation to the accuracy of MERC's load forecasting during the February Event. That is, CUB concluded that due to

⁴¹⁰ *Id.* at 56.

⁴¹¹ Ex. 506 at 25-26 (King Direct) ("Purchases for the Four-Day period of February 13-16 faced the ratable market requirement.").

⁴¹² Ex. 403 at 56 (Mead Direct).

⁴¹³ *Id.*

⁴¹⁴ *Id.* at 59.

⁴¹⁵ *Id.*; Ex. 408 at 24 (Sexton Direct).

⁴¹⁶ Ex. 506 at 109 (King Direct) (no disallowance depicted in the storage row for MERC).

MERC's load forecasting for February 17, 2021, MERC did not optimize its use of storage.⁴¹⁷

303. MERC initially made storage withdrawal nominations consistent with its maximum storage contract rights. Then MERC utilized its contracted storage flexibility to reduce its storage nominations during the day such that MERC's total flowing supplies were within allowable pipeline balancing tolerances versus total demand requirements on the system. As a result, based upon the information that MERC-NNG had available at the time it made gas supply purchases, storage nominations were at maximum levels and as a result, MERC maximized the use of its storage capacity during the February Event.⁴¹⁸

304. MERC acted prudently with regard to its use storage of its storage capacity, and no disallowances are warranted with respect to this issue during the February Event.

X. Additional Undisputed Issues

A. MERC's Conservation Messaging

305. The Commission's Order for Hearing requested development of the record as to whether the Gas Utilities should have made more robust conservation efforts during the February Event.⁴¹⁹

306. MERC provides its customers with energy conservation messages and energy saving tips throughout the year. These communications are provided in bill inserts, through MERC's website, and on its social media channels.⁴²⁰

307. MERC did not request that customers turn down thermostats or take other action in response to prices during the February Event due to how natural gas is purchased on the market. MERC completes all of its daily gas purchases early in the morning, to ensure it is able to secure adequate supply to serve forecasted customer needs. Once the commitment to purchase natural gas in the market was made on the morning of Friday, February 12, 2021, MERC was unable to adjust its daily volumes of gas.⁴²¹

308. Prudence did not require MERC to issue a broad conservation appeal to try to mitigate cost associated with the February Event. Voluntary conservation requests have significant limitations in terms of gas supply planning and cost mitigation, especially under the circumstances experienced during the February Event. If, in anticipation of voluntary conservation requests, MERC had reduced its daily gas purchases and ended up short, pipeline penalties would have significantly exceeded avoided gas costs.⁴²²

⁴¹⁷ Ex. 801 at 54 (Cebulko Direct).

⁴¹⁸ Ex. 409 at 8-9 (Sexton Rebuttal).

⁴¹⁹ Order for Hearing at 22.

⁴²⁰ Ex. 400 at 29 (Eidukas Direct).

⁴²¹ *Id.* at 29-30.

⁴²² *Id.* at 30.

309. The Department agrees that it was reasonable for the gas utilities, including MERC, not to have reduced their spot market purchases during the February Event for planned conservation pleas. In addition to timing and volume estimation issues, conservation pleas are traditionally a last-resort reliability tools.⁴²³

310. No other party disputed MERC's actions on this issue or recommended a disallowance attributable to conservation appeals.

311. MERC's actions related to conservation messaging before and during the February Event were prudent and reasonable, and no disallowance is recommended related to conservation messaging.

B. MERC's Use of Daily Index Priced Versus Fixed-Price Natural Gas Supply During the February Event

312. The Commission's Order for Hearing directed consideration of whether the Gas Utilities should have had additional fixed-price contracts.⁴²⁴

313. MERC utilized daily index pricing versus fixed-price gas supplies during the February Event.⁴²⁵ MERC generally purchases any daily gas at index prices.⁴²⁶

314. MERC has purchased index priced gas when in the short-term market to ensure it is not paying higher than the midpoint of the price where the gas trades. By nature of a fixed-price product, the buyer and seller are setting a rate for a predetermined period of time, and there is as much chance of being above the index as there is of being below the index. The index price, in contrast, reflects the midpoint of the market, and therefore will not be above where the market settles.⁴²⁷

315. It was reasonable for MERC-NNG to purchase its daily natural gas supplies based upon the Gas Daily Index price compared to purchasing at fixed daily prices. Use of the Gas Daily Index price ensures that natural gas costs are consistent with average market conditions. As a result, purchasing daily gas at daily index prices is a reasonable and prudent decision.⁴²⁸

316. The Department concluded that the utilities should not have made more fixed-price purchases.⁴²⁹ "Buying at a fixed-price represents a risk that the price paid could ultimately be higher or lower than the index. . . . [T]he Gas Utilities should [not] be expected to systematically beat the index" ⁴³⁰

⁴²³ Ex. 506 at 102-03 (King Direct).

⁴²⁴ Order for Hearing at 22.

⁴²⁵ Ex. 408 at 32 (Sexton Direct).

⁴²⁶ Ex. 403 at 53 (Mead Direct).

⁴²⁷ *Id.*

⁴²⁸ Ex. 408 at 36-37 (Sexton Direct).

⁴²⁹ Ex. 506 at 75-76 (King Direct).

⁴³⁰ *Id.* at 76.

317. MERC's use of daily index prices during the February Event was prudent and reasonable, and therefore, no disallowance is warranted on this issue.

C. Post February Event Actions

318. The Commission's Order for Hearing directed that the record be developed regarding whether the Gas Utilities have 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.⁴³¹

319. Following the February Event, MERC took steps to investigate and pursue any opportunities for potential offsets or recoveries related to the extraordinary gas costs. MERC has also evaluated the potential for market reform or gas purchasing modifications going forward to avoid or mitigate the impacts of a similar future event.⁴³²

320. Following the February Event, MERC evaluated possible sources of recovery or offsets, including through insurance, federal regulatory actions, market rules, contract enforcement, or other potential legal and legislative actions.⁴³³

321. MERC reviewed its contracts that were in force and applicable to natural gas purchased during the February Event to ensure that all charges assessed were consistent with contract terms. Through that review, MERC verified all of the gas supply invoices to ensure the volumes and dollars were billed according to the contract terms.⁴³⁴

322. MERC has not identified any contractual or other legal basis to challenge the validity of its supply contracts or the amounts paid for gas purchased and delivered. However, MERC continues to review its contracts with suppliers and pursue all available remedies and, if any are identified, to recover overpayments made to suppliers during the February Event. To the extent MERC recovers any proceeds from those efforts, MERC will notify the Commission and return those amounts to customers.⁴³⁵

323. MERC evaluated whether any available insurance policies would provide coverage for the costs incurred during the February Event and confirmed that no such coverage was available.⁴³⁶

324. MERC continues to actively monitor for any developments with respect to federal or state investigations into potential market manipulation related to the February Event.⁴³⁷

⁴³¹ Order for Hearing at 22-23.

⁴³² Ex. 400 at 32-33 (Eidukas Direct).

⁴³³ *Id.* at 33.

⁴³⁴ *Id.*

⁴³⁵ *Id.* at 33-34; Ex. 401 at 38 (Eidukas Rebuttal).

⁴³⁶ Ex. 400 at 34 (Eidukas Direct).

⁴³⁷ *Id.*

325. On February 22, 2021, FERC announced that its Office of Enforcement is examining wholesale natural gas and electricity market activity during the extreme cold weather to determine if any market participants engaged in market manipulation or other violations. According to FERC, if the Office of Enforcement finds any potential wrongdoing that can be addressed under FERC's statutory authority, it will pursue those matters as non-public investigations. On September 28, 2021, in a Senate Committee on Energy and Natural Resources Hearing to review the administration of law within FERC's jurisdiction, FERC Chairman Richard Glick stated, that FERC had "entered into a number of inquiries with regard to alleged [price] manipulation that occurred" and that "[s]everal of them, we found a number of anomalies. Several of those particular anomalies, when we investigated them, we moved on to what we call our investigations office."⁴³⁸

326. The February Event is under examination by a multi-organizational group led by FERC and NERC. That group presented preliminary findings and recommendations at FERC's open meeting on September 23, 2021, with final findings and recommendations expected this winter. MERC has and will continue to track those findings and recommendations, and evaluate whether there are any opportunities to participate or advocate for forward-looking changes that could be implemented to prevent against future market events.⁴³⁹

327. FERC's 2021 Annual Report on Enforcement also summarized a joint FERC/North American Electric Reliability Corporation report that is examining the impact of the weather event in February 2021 and includes 28 formal recommendations that seek to prevent a reoccurrence of the event. MERC continues to review these reports and will notify the Commission of updates.⁴⁴⁰

328. Because MERC met its balancing obligations on the NNG Pipeline, MERC received a credit from NNG related to shipper daily delivery variance charges (DDVC). This credit of \$763,179.25, will be credited to its customers in MERC's 2021-2022 AAA that will be filed on September 1, 2022.⁴⁴¹

329. MERC indicates it is committed to working with the Department, the Commission, the OAG, CUB, and other stakeholders, to identify opportunities for improvement, including advocating for possible market reforms, to the extent such reforms could provide future protection against similar market price spike events in the future.⁴⁴²

330. No party has disputed the prudence and reasonableness of MERC's actions after the February Event to investigate and pursue recovery through any available

⁴³⁸ *Id.* at 34-35.

⁴³⁹ *Id.* at 35.

⁴⁴⁰ Ex. 401 at 38 (Eidukas Rebuttal).

⁴⁴¹ Ex. 400 at 36 (Eidukas Direct); Ex. 401 at 38 (Eidukas Rebuttal).

⁴⁴² Ex. 401 at 39 (Eidukas Rebuttal).

contract enforcement, insurance, federal regulatory action, market rules, or other legal action.

331. The Department contends that many of the facts related to the February Event are still being discovered. The Department urges the Commission to withhold a prudency finding on this issue and to continuing reviewing regulatory developments and the Gas Utilities' filings as to their efforts to obtain recovery from other sources.⁴⁴³ At this time, however, MERC has complied with the Commission's direction that it explore other avenues for recovery and make compliance filings regarding its efforts. As a result, the record does not provide a basis for the Commission to withhold a prudency determination. Rather, the Commission should make an initial determination that MERC has acted prudently. The Commission should require ongoing compliance filings related to this issue, and if further developments warrant, it may make adjustments to MERC's cost recovery at that time.

D. 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?

332. The Commission's Order for Hearing directed that this Report consider whether it is possible to assign extraordinary gas costs to customers or customer classes based on their consumption during the February Event, and if so, whether it would be reasonable to do so.⁴⁴⁴

333. MERC provided evidence indicating that it could not directly assign extraordinary gas costs to individual customers or customer classes based on actual usage during the February Event. Even if daily customer meter data were available to allow for the allocation of these costs based on individual customer usage during the February Event, that assignment would not result in a more reasonable recovery of the extraordinary gas costs than the recovery mechanism the Commission has approved.⁴⁴⁵

334. This issue is not disputed by any party to this proceeding.⁴⁴⁶ The Department acknowledges that the Gas Utilities lack the metering and billing infrastructure that would be necessary to conduct cost assignment and billing based on February Event consumption.⁴⁴⁷

335. The Department concluded that allocation of the extraordinary February Event costs based on customer usage over the going-forward cost recovery period can be a reasonable approximation of usage during the February Event.⁴⁴⁸ The Department further concludes that the Commission's approved allocation methodology achieves the goals of having rate that are simple, understandable, and affordable by lengthening cost

⁴⁴³ Department Initial Br. at 81-82 (Mar. 15, 2022) (eDocket No. 20223-183839-07).

⁴⁴⁴ Order for Hearing at 23.

⁴⁴⁵ Ex. 400 at 41-44 (Eidukas Direct).

⁴⁴⁶ See Ex. 506 at 107-08 (King Direct).

⁴⁴⁷ *Id.* at 107.

⁴⁴⁸ *Id.* at 108.

recovery, phasing in the rate, seasonally adjusting the rate, and exempting certain customers.⁴⁴⁹

336. The Department supported tracking customers who received sales service during the February Event who switch to transportation service to avoid paying the extraordinary cost surcharge.⁴⁵⁰ MERC's approved rates are applied to customers who received sales service during the February Event, even if those customers move to transportation service.⁴⁵¹

337. Under applicable rules and tariffs, MERC normally recovers gas commodity costs through the PGA, which is set at the beginning of each month based on forecasted gas costs and sales volumes. Gas cost true-up amounts, which reflect the amounts over- or under-recovered each month through PGA rates, are normally handled under the procedures set forth in Minn. R. 7825.2700, subp. 7 and Minn. R. 7825.2910, subp. 4. These two rules require a 12-month recovery period, beginning September 1 each year, through a volumetric surcharge or refund rate.⁴⁵²

338. Due to the magnitude of costs associated with the February Event, the Gas Utilities agreed that collection of these costs should not follow the traditional true-up process. Under the approved rate recovery, customers who are receiving or have received Low Income Home Energy Assistance and residential customers who are 60 to 120 days in arrears are exempted from the surcharge rates.⁴⁵³

339. In accordance with the Commission's August 30, 2021, Order, extraordinary gas costs are being recovered through the volumetric surcharge with variable summer and winter rates and a step in rates in the second year of recovery, with protections for low income customers. Phased recovery provides time for the Commission's prudence review to be completed and to explore possible cost offsets, including federal or state funding and other offsets, before the step-in recovery is implemented in 2022. Recovery over 27 months balances considerations of intergenerational inequities that result from out-of-period adjustments.⁴⁵⁴

340. The record supports continuation of the approved recovery approach based on current customer natural gas usage and continuation of tracking for customers who received system sales service during the February Event who switch to transportation service.

⁴⁴⁹ *Id.*

⁴⁵⁰ *Id.* at 108-09.

⁴⁵¹ Ex. 401 at 37 (Eidukas Rebuttal)

⁴⁵² Ex. 400 at 37 (Eidukas Direct).

⁴⁵³ *Id.* at 38-39.

⁴⁵⁴ *Id.* at 44. It should be noted that the Commission is considering whether to extend the cost recovery over a longer period and requested public comments on that issue. As of this time, the Commission has not varied from the 27-month recovery period it previously approved. See Notice of Comment Period (Jan. 28, 2022) (eDocket No. 20221-182103-03); see *also* Compliance Filing (Apr. 1, 2022) (eDocket No. 20224-184346-01).

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

CONCLUSIONS OF LAW

1. The Commission and the Administrative Law Judges have jurisdiction over this proceeding pursuant to Minn. Stat. § 14.50 and Chapter 216B (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.⁴⁵⁵

4. The burden to prove that its actions were prudent and that recovery of extraordinary costs is reasonable rests on MERC.⁴⁵⁶

5. Utilities do not enjoy a presumption of prudence.⁴⁵⁷ Doubts as to reasonableness are resolved in favor of the consumer.⁴⁵⁸

6. MERC 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 MERC 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 MERC to serve its customers during the February Event were prudently incurred.

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

⁴⁵⁵ Minn. Stat. § 216B.03.

⁴⁵⁶ Minn. Stat. § 216B.16, subd. 4.

⁴⁵⁷ *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).

⁴⁵⁸ Minn. Stat. § 216B.03; see also Order for Hearing at 3.

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

Dated: May 24, 2022


JESSICA PALMER-DENIG
Administrative Law Judge


BARBARA CASE
Administrative Law Judge

NOTICE

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

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

May 24, 2022

See Attached Service List

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

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Recovery Process for Cost Impacts Due to February Extreme Gas Market Conditions

**OAH 71-2500-37763
MPUC G-011/M-21-611**

To All Persons on the Attached Service List:

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

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

Sincerely,



MICHELLE SEVERSON
Legal Assistant

Enclosure
cc: Docket Coordinator

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

CERTIFICATE OF SERVICE

<p>In the Matter of the Petitions for Recovery of Certain Gas Costs</p> <p>In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Recovery Process for Cost Impacts Due to February Extreme Gas Market Conditions</p>	<p>OAH Docket No.: 71-2500-37763 MPUC G-011/M-21-611</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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