Staff Briefing Papers

Meeting Date	July 28, 2022 (Oral Arguments) August 4, 2022 (Deliberations)	Agenda Item 3**
Company	Minnesota Energy Resources Corporation (MERC)	
Docket No.	**G-008/M-21-611** **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.**	
Issues	Should the Commission adopt the recommendations in the ALJ's Report? If not, what disallowance(s) should be approved?	
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✓ **Relevant Documents**	**Date**
Minnesota Public Utilities Commission – Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing	August 30, 2021
Minnesota Energy Resources Corporation – Direct Testimony and Schedules	
Timothy C. Sexton	October 22, 2021
Sarah Mead	October 22, 2021
Theodore T. Eidukas	October 22, 2021

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ **Relevant Documents**	**Date**
Joint Gas Utilities – Direct Testimony	
Richard G. Smead	October 22, 2021
Department of Commerce – Direct Testimony and Schedules	
Nancy Campbell	December 22, 2021
Matthew J. King (Public and Trade Secret)	December 22, 2021
Office of the Attorney General – Direct Testimony	
Brian Lebens (Public and Trade Secret)	December 22, 2021
Citizens Utility Board of Minnesota – Direct Testimony and Schedules	
Bradley Cebulko	December 22, 2021
Ron Nelson	December 22, 2021
Department of Commerce - Errata	
Department of Commerce – Matthew J. King Direct Testimony (Errata)	December 30, 2021
Minnesota Energy Resources Corporation – Rebuttal Testimony and Schedules	
Theodore T. Eidukas	January 21, 2022
Sarah R. Mead	January 21, 2022
Timothy C. Sexton	January 21, 2022
Joint Gas Utilities and Xcel Energy – Testimony and Errata	
Richard G. Smead Direct Testimony (Errata)	February 8, 2022
Richard L. Derryberry Direct and Rebuttal	February 8, 2022
Department of Commerce – Surrebuttal and Schedules	
Nancy Campbell	February 11, 2022
Matthew J. King	February 11, 2022

✓ **Relevant Documents**	**Date**
<u>Office of the Attorney General – Surrebuttal</u>	
Brian Lebens	February 11, 2022
<u>Citizens Utility Board of Minnesota – Surrebuttal</u>	
Bradley Cebulko	February 11, 2022
Ron Nelson	February 11, 2022
<u>OAH - ALJ Reports: Findings of Fact, Conclusions or Law, and Recommendation</u>	
ALJ Reports	May 24, 2022
<u>Exceptions to ALJ Reports</u>	
Citizens Utility Boards of Minnesota Arguments and Exceptions	June 3, 2022
OAG – Residential Utilities Division	June 3, 2022
Minnesota Energy Resources Corporation	June 3, 2022
Department of Commerce	June 3, 2022
<u>Exhibits</u>	
Minnesota Energy Resources Corporation - Exhibit 513	February 17, 2022
Department of Commerce – Hearing Cover	February 17, 2022
Minnesota Energy Resources Corporation – Exhibit 411	February 22, 2022

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I. Statement of the Issues

Should the Commission adopt the recommendations in the ALJ's Report? If not, what disallowance(s) should be approved

II. Introduction

On February 23, 2021, the Commission held a special planning meeting to hear comments from the rate regulated natural gas utilities, the Minnesota Department of Commerce, Division of Energy Resources, and the Minnesota Office of the Attorney General–Residential Utilities Division, on the impact of the February 2021 cold weather on the natural gas utilities and their customers (February Event).

Between March and July 2021, all regulated natural gas utilities,[1] the Minnesota Department of Commerce (Department), the Office of the Attorney General – Residential Utilities Division (OAG), Energy Cents Coalition (ECC), the Citizens Utility Board of Minnesota (CUB), the City of Minneapolis (Minneapolis), and the Suburban Rate Authority (SRA) filed comments and recommendations quantifying extraordinary February 2021 costs, recommending how much and how should the utilities be allowed to recover and what the recovery period should be.

On August 4 and 5, 2021, the Commission met to consider the recovery matter and, on August 30, 2021, it issued an *Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing* (August Order). The August Order:

- Defined the February Event to be February 13–17, 2021.
- Defined February Event extraordinary costs to be the margin between $20/dekatherm and the actual average price experienced by the utilities.
- Subject to prudence review, established that MERC's extraordinary costs are $64,975,882.
- Subject to prudence review, allowed MERC to recover non-extraordinary costs (i.e., $20/dekatherm) through its automatic adjustment in the annual true-up filing (AAA) docket.
- Extended MERC's extraordinary costs recovery period to 27 months.[2]
- Exempted MERC's low-income customers from paying for extraordinary costs.
- Approved extraordinary costs recovery using a volumetric charge with seasonally adjusted and stepped surcharge rates, with lower rates applied over the first 15 months and higher rates in the last 12 months.
- Denied MERC to include finance/carrying charges.

- Disallowed utilities from tracking and deferring to a regulatory asset any incremental bad debt expense associated with the February Event.

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[1] CenterPoint Energy, Xcel Energy, Minnesota Energy Resources Corp. (MERC) and Great Plains Natural Gas Co.

[2] Subsequently, as part of its acceptance of CenterPoint's most recent rate case in docket G-008/GR-21-435, the Commission extended the recovery period for all CenterPoint customers to 63 months.

- Referred recovery February Event costs to the Office of Administrative Hearings for a contested proceeding.

III. Background

On October 22, 2021, MERC filed direct testimony supporting its request to recover the full $64,975,882.

On December 22, 2021, the Department, the OAG, and CUB filed direct testimony recommending various disallowances, as discussed below.

On January 21, 2022, MERC filed rebuttal testimony disagreeing with all recommended disallowances.

On February 11, 2022, the Department, the OAG, and CUB filed rebuttal testimony continuing to recommend various disallowances, as discussed below.

On March 15, 2022, MERC, the Department, the OAG, and CUB filed initial briefs and proposed findings of fact.

On March 25, 2022, MERC, the Department, the OAG, and CUB filed reply briefs.

On May 24, 2022, the Office of Administrative Hearings filed a Summary Report of Public Hearings and on the same day the ALJs filed their report.

On June 3, 2022, the Department, the OAG, and CUB filed exceptions to the ALJ Report.

On June 6, 2022, LIUNA filed exceptions to the ALJ Report.

IV. Public Comments

As shown in Figure 1, 85 public comments were filed in this docket with over 70% of the commenters opposing recovery by the Company.

Figure 1 – Public Comments Summary

	Number of Comments	Percent
Rate Payers Opposed to surcharge	60	70.6%
Rate Payers Open to share costs with Utilities	24	28.2%
Allocate surcharge to designated period	1	1.2%
Total Public Comments:	**85**	**100.0%**

V. MERC's Procurement and Actions During the February Event

a. MERC's Procurement Process

In order to provide natural gas service to customers in the communities it serves, MERC secures adequate interstate pipeline capacity to allow for the delivery of natural gas supplies from areas where natural gas is produced to interconnection points on MERC's distribution system. As a result of MERC's disperse service areas four separate interstate pipelines are relied on to serve our various communities:[3]

- Centra Pipeline runs from Spruce Manitoba, Canada, into Minnesota from Warroad to Baudette. Centra Pipeline is used to serve communities in Northern Minnesota.
- Viking Gas Transmission Pipeline runs from Emerson 1 (TransCanada) on the U.S. side to serve our customers from Ada to Camp Ripley.
- Great Lakes Transmission Pipeline runs from Emerson 2 (TransCanada) on the U.S. side to serve our customers from Thief River Falls to Cloquet.
- Northern Natural Gas ("NNG") Pipeline runs from Ventura in Iowa (NMPL) and Demarcation ("Demarc") (near Clifton, Kansas) which is the transfer point for gas coming north from NNG's Field area to serve NNG's Market area to serve our customers in Southern Minnesota.

Based on the Commission's definition of extraordinary February 2021 gas costs as costs incurred from February 13-17 and the margin between $20/Dekatherm ("Dth") and the actual average daily price, MERC indicated that it incurred extraordinary gas costs of $64,975,882 associated with the February Market Event.[4]

MERC noted that, to provide natural gas service, it operates two distinct Purchased Gas Adjustment (PGA) areas within the State of Minnesota: Minnesota Energy Resources Corporation-Consolidated (MERC-Consolidated) and Minnesota Energy Resources Corporation-NNG (MERC-NNG).[5]

With very few exceptions, customers are served solely by a specific pipeline. These PGA areas are geographically separate, they do not share pipeline capacity, storage, or natural gas supplies.[6]

The main objective for MERC's gas supply portfolio is to provide reliable and reasonably priced natural gas. These objectives are accomplished through utilizing diverse purchase locations, multiple counterparties, firm transportation contacts, storage, hedging, FOM supply, call

[3] Theodore T. Eidukas Direct Testimony, at 5.

[4] Theodore T. Eidukas Direct Testimony, at 8.

[5] Timothy C. Sexton Direct Testimony, at 6.

[6] Sarah R. Mead Direct Testimony, at pp. 9-10.

options and daily priced supply, including multiple sources providing a diversity of supply points and prices where possible.[7]

MERC's diverse firm gas supply mix includes:

- Fixed-price financial (futures)
- Financial calls (options)
- Pipeline storage (NNG/ANR)
- FOM (First of Month) Index; and
- Daily Market – Gas Daily Index (GDD)

Additionally, MERC in conservation measures through an approved Conservation Improvement Program (CIP), which serves to reduce overall customer demand through increased efficiency. MERC estimated that it was able to avoid over $20 million of additional cost during the February Market Event.[8]

b. MERC-Consolidated PGA Area Natural Gas Sourcing

The MERC-Consolidated PGA service areas are directly connected to the Viking Gas Transmission (Viking), Great Lakes Gas Transmission (Great Lakes), and Centra Pipelines Minnesota Inc. ("PMI) pipeline systems. The Company asserted that it holds firm natural gas transportation capacity on the Viking and Great Lakes pipeline systems with firm primary receipt point rights into these pipes at Emerson, Manitoba (Emerson) at the US/Canadian border via interconnects between these pipelines and the upstream TransCanada pipeline system. Natural gas supplies are acquired at Emerson and then transported on Viking and Great Lakes to MERC-Consolidated PGA area markets directly connected to Viking and Great Lakes.[9] Additionally, MERC holds firm natural gas transportation capacity on the CPMI system as well as on CPMI's affiliated upstream Centra Transmission Holdings, Inc. (CTHI) pipeline. The Company stated that natural gas supplies are acquired into the CTHI system at a CTHI interconnect with the TransCanada Pipeline at Spruce, Manitoba. The gas is then transported on CTHI to CPMI at the US/Canadian border at International Falls, Minnesota. After crossing the border, the gas is transported on CPMI from International Falls to MERC-Consolidated PGA area markets directly connected to CPMI.[10]

[7] *Id*, at 12.

[8] During the February Market Event, MERC says its investments in CIP allowed MERC to avoid additional gas purchases, resulting in estimated avoided costs of approximately $21.3 million. See Docket No. G999/CI-21-135, Comments of the Minnesota Department of Commerce, Division of Energy Resources at Department Attachment 5 (MERC Response to Department Information Request No. 5) (May 10, 2021).

[9] Timothy C. Sexton Direct Testimony, at pp. 7-8.

[10] Id, at p. 8.

MERC noted that during the February Event, natural gas market prices at Emerson, Manitoba and Spruce did not experience price spikes to the level that would result in extraordinary costs. Consequently, the MERC-Consolidated PGA area did not incur any extraordinary costs.[11]

c. MERC-NNG Natural Gas Supply Sourcing

MERC reported that during the February Event, MERC-NNG had 195,556 Dth/day of firm pipeline transportation capacity on the Northern pipeline system from various receipt points to MERC-NNG PGA area markets. Furthermore, the Company noted that upstream of the Northern pipeline system, 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. The capacity held on Northern Border was subject to a capacity release agreement and Asset Management Agreement (AMA) with a third party during the February Event.[12]

The AMA was entered into to mitigate daily capacity reservation fees and reduce associated gas costs. Under its terms, the counterparty paid MERC an annual fee in return for the rights to 40,000 Dth/day of MERC's firm transportation capacity on Northern Border. Moreover, MERC and the AMA Counterparty entered into a call option agreement under which, when called upon by MERC, the Counterparty agreed to provide 40,000 Dth/day of supply to MERC at Ventura.

During the February Event, MERC had four upstream natural gas supply sources available into its firm capacity on Northern for ultimate delivery to customers on the MERC-NNG PGA area markets. The four locations were:

- Northern pipeline interconnects with Great Lakes at Carlton and Grand Rapids, Minnesota.
- Northern's Field to Market Demarcation point (Demarc).
- Northern pipeline interconnects with Northern Border at Ventura, Iowa; Welcome, Minnesota; Marshall, South Dakota; and Aberdeen, South Dakota.
- 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 Northern Border into Northern at MERC's available receipt point capacity at Northern's interconnects with Northern Border.

Table 1 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.

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[11] Id, at p. 9.
[12] Timothy C. Sexton Direct Testimony, at pp. 9-10.

Table 1 – 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**

d. MERC-NNG Geographic Diversity of Supply

MERC stated that it utilized the geographic diversity in its portfolio to minimize exposure to rising daily gas prices during the February Event. The Company observed that, 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 small degree at Northern-Demarc.

MERC pointed out that with natural gas demand and prices rising during the February Event, the only choice to maintain the natural gas supplies required to serve customers in the MERC-NNG PGA area was to obtain incremental daily supplies at Demarc or Ventura based pricing.[13] With the limited locations in its portfolio that were available to source supplies during the February Event, the Company utilized the geographic diversity in its portfolio.

e. Natural Gas Supply Liquidity and Availability at MERC-NNG Supply Receipt Points

Ventura and Demarc are significant trading points with large quantities of natural gas purchased and sold each day, creating liquid trading points for natural gas purchases and sales. The liquid markets at Ventura and Demarc are an important feature in MERC-NNGs supply portfolio as the liquidity as these locations provide MERC with a greater level of certainty that

[13] Timothy C. Sexton Direct Testimony, pp. 13-14.

natural gas supplies can be purchased on the daily market to meet system demand requirements during cold and/or peak design day conditions.

f. Natural Gas Supply Liquidity and Availability at the Great Lakes – Grand Rapids Receipt Points

According to Northern's Electronic Bulletin Board (EBB), Northern's interconnect with Great Lakes at Grand Rapids, Minnesota has a total design receipt capacity of only 24,000Dth/day.[14] In order to ensure natural gas supplies are available into Northern at this location under cold weather conditions, natural gas purchases must be arranged prior to the winter season as term or baseload supply.[15]

g. Natural Gas Supply Liquidity and Availability at the Great Lakes – Carlton Receipt point

As designed, in order to support design day operations and enable Northern to meet firm market demand requirements, Great Lakes must receive a base quantity of supply at the northern most points on its pipeline system. In order to achieve this, Northern has a tariff right, known as the Carlton Obligation, to impose an obligation on a specific set of shippers, such as MERC, defined as "Sourcers" in Northern's FERC Gas Tariff, Sixth Revised Volume No. 1 (FERC Gas Tariff).[16] When called upon by Northern, they must receive a predefined quantity of gas at Carlton or other similar points agreed to by Northern. Failure to receive their Carlton Obligation quantity would be subject to penalties and potential capacity curtailments. Consequently, maintaining receipts at Carlton is critical for shippers on Northern, such as MERC, not only to meet cold weather customer demand requirements but also to comply with Northern's FERC Gas Tariff.[17]

MERC noted that there is no liquid market for daily supply transactions at Carlton. As such, to meet system requirements, MERC purchased supplies at Carlton on a first of month (FOM) baseload basis. This baseload supply from Carlton was utilized to meet MERC-NNG PGA area demand requirements during the February Event.

h. MERC's Use of Storage during the February Event

The Company asserted that natural gas storage provides its primary means of balancing supply and demand day-to-day through nominations. In addition to operational benefits, the Company asserted that storage provides a physical price hedge for customers by reducing the amount of gas purchased in the winter and increasing the amount purchase in the summer for delivery at a later date.[18]

[14] Timothy C. Sexton Direct Testimony, p 16.
[15] Id.
[16] Northern's FERC Gas Tariff, Sixth Revised Volume No. 1, First Revised Sheet Number 263.
[17] Timothy C. Sexton Direct Testimony, at p. 17.

[18] Sarah R. Mead Direct Testimony, at 23.

MERC noted that it 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 noted that during the 2021 February Event, it had two Firm Deferred Delivery (FDD) rate schedule storage agreements with Northern to meet demand requirements for MERC customers on the MERC-NNG PGA.[19] Table 2 summarizes these storage service agreements and capacities (Maximum Storage Capacity (MSQ), Maximum Daily Withdrawal Quantity ("MDWQ") and Maximum Daily Injection Quantity (MDIQ) available to MERC.

Table 2 – MERC-NNG Storage Capacity During February Event

NNG FDD Contract	MSQ (Dth)	MDWQ (Dth/day)	MDIQ (Dth/day)
118657	6,019,321	80,642	24,184
132024	500,000	6,699	2,009
Total	**6,519,321**	**87,341**	**26,193**

As indicated in Table 2, MERC-NNG had a total of 87,341 Dth/day of withdrawal capacity available during the February Event.

i. Call Options for Gas

Call options provide a right to call upon gas supply for a certain number of days for a specific period and location within a predetermined price, typically priced around the daily market. The benefit of call options 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 during low-demand days at a loss. MERC stated that it contracted for call options during the 2020-2021 winter period.[20]

j. Daily Gas Purchases

The Company cited that the use of daily supply purchases provides needed flexibility to address the reality of variability in weather and customer load over each month or the heating season. The possibility of purchasing baseload supplies in excess of what is needed to serve customer demand in normal weather creates a significant risk that MERC would have to sell, most likely at a loss, during each day that a peak was not experienced. Hence, MERC purchases monthly and daily gas in line with sales customers' needs.

[19] *Id*, p. 24.
[20] Sarah R. Mead Direct Testimony, at 36.

k. MERC's Use of Daily Index-Priced vs Fixed-Priced Natural Gas Supply

During the February Event, MERC-NNG activated its daily call option (39,245 Dth/day of supply) into Northern at Ventura at Gas Daily index pricing. Additionally, MERC-NNG made daily purchases of 54,641 Dth/day at Ventura and 2,376 Dth/day at Demarc for the period February 13-16, on a ratable basis. Finally, on February 17 MERC-NNG purchased 30,000 Dth/day of daily purchases at Ventura.[21]

These daily gas purchases were made based on the price published as the Midpoint price by Platts Gas Daily within the Final Daily Price Survey for relevant Flow Date and Location. According to Platts' Gas Daily publication:

> "Platts Gas Daily indices are based upon trade data reported to Platts by market participants and the Intercontinental Exchange. The indices are calculated using detailed transaction level data from these providers. Platts editors screen the data for outliers that may be further examined and potentially removed. A volume weighted average is then calculated from the remaining set of data."

MERC noted that "the Gas Daily Index Price represents the volume weighted average price of transactions for a specific flow date (or dates if covering a weekend or holiday period) at any particular reported location".[22]

The Company asserted that it is standard industry practice to purchase gas at index-based prices and stated that the vast majority of natural gas purchased and sold in US markets is done at index prices. In December 2020, FERC staff provided a presentation in FERC Docket No. PL20-3-000 which included an observation based upon the data collected from market participants in FERC Form 552. Within the presentation, FERC staff observed that, in 2019, 82% of the traded volume of natural gas transactions referenced natural gas indices.[23] Further, FERC posted the transactional information collected through the Form 552 process for calendar year 2020 in which approximately 83% of natural gas purchases referenced index price mechanisms,[24] an indication that this is the standard industry practice.

According to MERC, use of the Gas Daily Index price insulates MERC-NNG and its customers from the risk inherent in the daily market volatility and ensures that natural gas costs are consistent with average market condition.

In conclusion, based on the direct testimony of Timothy C. Sexton, MERC's actions and decisions before and during the February Event related to natural gas supplies were appropriate. He

[21] Timothy C. Sexton Direct Testimony, at 34.
[22] *Timothy C. Sexton Direct Testimony,* at 35.
[23] https://cms.ferc.gov/news-events/news/staff-presentation-price-index-policy-statement-and-safe-harbor-price-index-nopr.

[24] Staff Presentation on Price Index Policy Statement and Safe Harbor Price Index NOPR (PL20-3-000, RM20-7-000), https://cms.ferc.gov/news-events/news/staff-presentation-price-index-policy-statement-andsafe-harbor-price-index-nopr.

asserted further that MERC made prudent and reasonable decisions regarding the use of its available portfolio of services and supplies to minimize gas costs during the event.[25]

VI. Disputed Issues

A. Storage and Load Forecasting

This issue is disputed between the Company, the Department and Citizens Utility Board of Minnesota (CUB). The Department and CUB stated that MERC made errors in its load forecasting and CUB stated that MERC did not optimize its use of storage during the February Event. As a result, The Department recommended a $9,707,206 disallowance and CUB recommended a (revised) disallowance range of $1,649,837 to $3,903,233.

a. MERC – Direct

The Company reported that based upon forecasted demand the day ahead of gas flow, MERC nominated and scheduled withdrawals of 87,341 Dth/day each day of the February Event during Northern's Timely Nomination cycle.

MERC reviewed its forecast for system demand requirements one day prior to gas flow (or the prior to February 13, in the case of the four-day period of February 13 -16, 2021) when received at 7:30 a.m.[26] Given that forecasted system demand includes demand for MERC's on-system Transportation service customers, the next step in MERC's process was to subtract the Transportation customer demand from total forecasted demand to develop forecasted system sales demand for the day.[27] Finally, MERC noted that it subtracted: (a) available delivered baseload supplies (b) available delivered AMA call supplies; and (c) available storage withdrawal capacity (at 100% of contract capacity rights) from the forecasted system sales demand to determine required daily supply purchases for the day of flow.[28]

Additionally, MERC indicated that the Company purchased a small (< 2%) reserve supply to ensure that actual demand requirements were fully supported and to avoid any under-delivery penalties.

Given that natural gas commodity markets are not active during weekends and holidays, 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). Since Monday, February 15, 2021 was a holiday (President's Day), MERC completed daily gas purchases on Friday, February 12, 2021 for the four-day period: February 13 -16, 2021 based on the highest forecasted demand day over the period. [29]

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[25] Timothy C. Sexton Direct Testimony, at 43.
[26] The MAXX/Marquette Gas Day Forecast as of 7:30 AM on 02/12/2021.
[27] Timothy C. Sexton Direct Testimony, at p. 25, Line 8-11.
[28] *Id*, at 26.
[29] *Id*, at 29.

Given that natural gas supplies had to be taken ratably (at the same quantity each day) over the four-day period of February 13-16, MERC could not adjust supplies during this timeframe to match demand requirements. MERC asserted that its only option to balance supplies with actual deliveries each day was to adjust storage withdrawals during the day.[30] The Company noted that it is an FDD storage service capacity customer with Northern. Northern provides MERC with the capability to reduce storage nominations at the end of each day of gas flow via a "23rd hour storage nomination" made no later than 8:00 a.m. This 23rd hour storage nomination enables MERC to reduce its daily withdrawal quantity to the extent necessary to balance supplies with demand requirements.

In order to provide natural gas service to customers in the communities it serves, MERC plans for secured adequate interstate pipeline capacity to allow for the delivery of natural gas supplies from areas where natural gas is produced to interconnection points on MERC's distribution system. As a result of MERC's disperse service areas four separate interstate pipelines are relied on to serve their various communities:

- Centra Pipeline runs from Spruce Manitoba, Canada, into Minnesota from Warroad to Baudette. Centra Pipeline is used to serve communities in Northern Minnesota.
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b. Citizens Utility Board of Minnesota – Direct

CUB cited that MERC over-projected MERC-NNG load by 10% and 34% on February 14 and 17, respectively. The utility was therefore forced to ramp down storage withdrawals by 17% on February 14, and by 49% on February 17 to match supply with demand. MERC's forecasting errors for MERC-NNG led to the over-procurement of spot gas purchases for each day of the long weekend and the need to reduce storage over these dates was higher than necessary and reach a maximum reduction of 49%.[31] CUB noted that MERC argued that "storage nominations were at maximum levels and as a result, MERC maximized the use of its storage capacity during the February Event."[32]

CUB noted that, despite having the ability to do so with better planning, MERC significantly over-procured gas and was not able to maximize storage withdrawals. CUB stated that MERC was aware of price volatility in the spot market and that MERC substantially over-projected load

[30] *Id*, at 30-31.
[31] Bradley Cebulko Direct, at 54, lines 3-9.
[32] Sexton Direct, p. 32, lines 12-14.

for MERC Northern Natural Gas (NNG) on the key planning dates of February 14 and 17.[33] According to CUB, the scale of MERC over-projections was not justified within MERC's direct testimony. CUB further stated that as a result of the Company's conservative forecasting for MERC-NNG, MERC was unable to maximize storage to the extent that would have been possible with less over-supply. Additionally, CUB contends that MERC did not request any curtailments during the Event. As shown in Table 3, due to the MERC's "unreasonably conservative load forecasting" and subsequent failure to maximize storage on the key planning dates of February 14 and 17, CUB recommended disallowances ranging between $8,454,945 and $18,028,508.[34]

Table 3 – CUB's Recommended Load Forecasting and Storage Disallowance Recommendation

Load Forecasting Error and Storage Optimization	5% Forecasting Error	10% Forecasting Error
2/13 – 2/17	$18,028,508	$8,454,945
2/17 Only	$10,202,942	$8,454,945

Additionally, CUB asserted that MERC did not act prudently during the time leading up to the storm. MERC failed to significantly change course on February 16 when they developed a supply plan for gas day February 17. CUB argued that MERC knew that prices had reached unprecedented levels, and had incurred incremental costs in the millions of dollars, but continued not to maximize curtailments, peaking facilities, and their storage to mitigate the cost impact to customers.[35] CUB further stated that, although MERC correctly identified how reductions in storage were needed to balance the system, they did not mention how their over-procurement of spot gas contributed to the need to ease off storage.

c. Department of Commerce – Direct

The Department noted that the error for February 14 and 17 was the most impactful to extraordinary costs, as the forecast for those days determined the Gas Utilities' spot purchases. MERC-NNG over-forecasted 8%. Over-forecasting on February 14 translated to purchasing more spot gas than needed for each day of the Four-Day Period.

MERC-NNG load forecast for February 17 appeared unreasonably high.[36] February 17 was the warmest day of the February Event but MERC-NNG's load forecast was the second highest, behind only February 14. The large forecast error was due to MERC's February 17 partial adjustment that accounted for its transportation customer usage shifting during the event. The Department recounted that MERC first forecasted its total, system load (transportation and

[33] Ronald Nelson Direct Testimony, at 10.

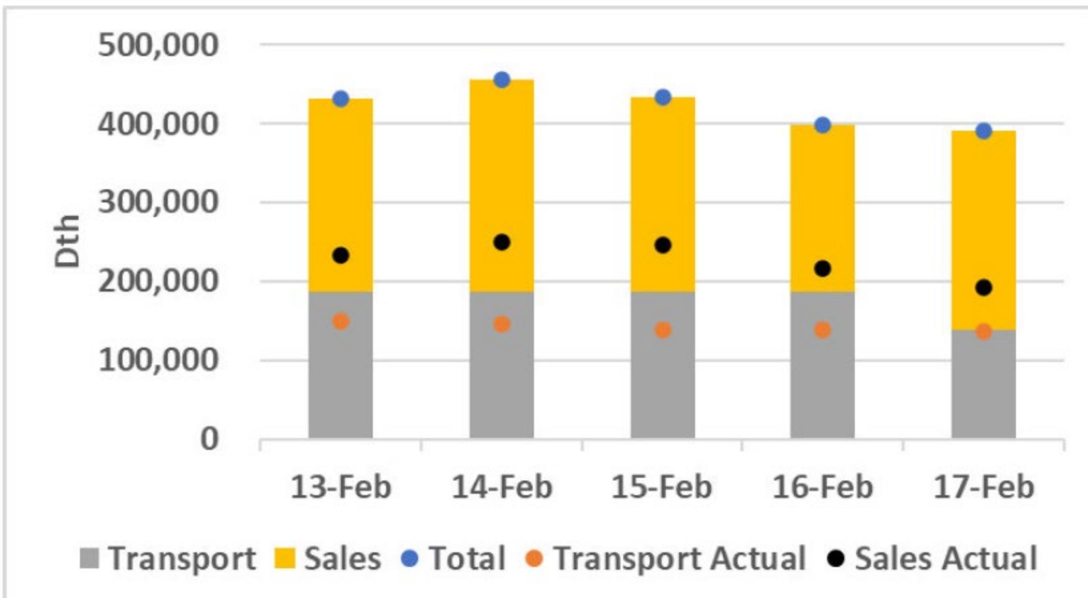
[34] Bradley Cebulko Direct, at 59, lines 5-8.

[35] Ronald Nelson Direct Testimony, at 31, lines 12-10.

[36] Matthew J. King Direct Testimony, at 68, lines 7-11.

sales customers) and then removed what it knew about transportation customer load to derive a sales customers' forecast. The derived sales forecast was used to determine supply needs. Transportation customer load dropped significantly throughout the February Event as compared to pre-event levels.[37] It appears that MERC accounted for the lower transportation customer usage seen over the Four-Day period but only in the transportation customer forecast and not in the system-wide forecast. By significantly reducing the transportation customer load expectation for February 17 without a commensurate change in the system-wide load forecast, the sales customer forecast was inflated.[38] Table 4 below illustrates MERC-NNG's forecasts across the February Event for both transportation and sales customers and compares those to actual load.

Table 4: MERC-NNG Sales/Transportation Forecast vs Actuals[39]



As a result of MERC's error, the Department calculated a disallowance by estimating the reduction in the transportation customer sales forecast, based on the prior day's forecast and applied that reduction to the system-wide forecast to derive a reduced sales customer forecast. The reduction in the sales customer forecast translates to less spot gas purchases, which are priced at MERC-NNG's average spot gas price for February 17. The Department's resulting disallowance recommendation was $9,707,206.

d. MERC – Rebuttal

MERC disagreed with CUB's assessment and stated that none of the identified information that was known on February 12 would have supported the Company taking actions outside the range of standard industry practice, inconsistent with the Company's planning and historical operations, or inconsistent with the Company's tariffs, approved rate structure, or Commission

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[37] *Id.*
[38] Matthew J. King Direct Testimony, at 69, lines 12-19.
[39] Data from MERC Ex. __, SRM-D-7 (Mead Direct).

authorizations. Even after the magnitude of prices over the four-day weekend were known, when planning to meet customer requirements on February 17, it would still not have been reasonable for MERC to have taken actions outside the range of standard industry practice, inconsistent with the Company's planning and past operations, or inconsistent with Commission-approved tariffs, approved rate structures, or Commission authorizations.[40]

e. CUB – Surrebuttal

Based on the revised load forecast numbers MERC provided on Rebuttal, the utility's load forecasting error was within CUB's range of reasonableness for February 13 through 16; however, CUB still found MERC's February 17 load forecast to be unreasonable. As shown in Table 5, CUB revised its load forecasting and storage disallowance recommendation to a range of $1,649,837 to $3,903,233.[41]

Table 5 – CUB's Revised Recommended Load Forecasting and Storage Disallowance Recommendation

Load Forecasting Error and Storage Optimization	5% Forecasting Error, Reserve Margin (2.85% - 10.44%)	10% Forecasting Error, Reserve Margin(2.85% - 10.44%)
2/13 – 2/17	$3,903,233	$1,649,837
2/17 Only	$3,903,233	$1,649,837

CUB stated that MERC has neglected to articulate a "reasonable" forecasting error, which is problematic given that utilities forecast load routinely. If MERC is neglecting to analyze its forecasting errors, it would be ignoring key data for improving forecasts. CUB does not believe that the Commission intends to dismiss these forecasting accuracy arguments simply because load forecasts are forward-looking by nature. Such a practice would implicitly authorize over-procurement due to inaccurate load forecasts, which would not lead to just and reasonable rates.[42]

f. ALJ Report

The ALJ found that:

> 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.
>
> 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.

[40] Mead Rebuttal, pp. 8-10.

[41] Bradley Cebulko Surrebuttal, pp. 5, 7.

[42] Cebulko Surrebuttal, pp. 16-17.

g. Exceptions to ALJ Report

In its exceptions, the Department stated that MERC's failure to appropriately reflect transport customer forecasts in its system-wide forecast led to purchasing substantial amounts of unnecessary, extremely expensive spot gas. The ALJs' findings generally defer to a myriad of justifications and factors that have little empirical support and recommend the utilities recover millions of dollars for purchases of unused expensive spot gas from ratepayers. The Commission should exercise its experience and expertise with forecasting and supply planning and determine that the record does not support the utilities recovering these imprudent costs. ALJs simply deferred to MERC's rationale for why they purchased so much excess gas and allowed the utilities to recast their unreasonable load forecasting and storage withdrawal decisions as planning on supply reserve margins of 10%. The ALJs allowed the utilities to claim whatever supply reserve margin fit their theory of the case was reasonable and once again put the onus on the Commission to micromanage utilities by reining in excessive supply reserves in another docket. The ALJs' findings on load forecasting indicate that, unless the Commission establishes "specific parameters to govern the Gas Utilities' load forecasting procedures and outcomes" or sets "standards identifying a particular supply reserve margin figure as reasonable," utilities will be granted immunity for all gas procurement decisions. The prudence standard does not dictate blind deference to utilities. Instead, it requires that utilities to show their actions are prudent to recover costs from ratepayers. No order or regulation detailing exact utility operations is needed to require the utilities to act reasonably under the circumstances, including by reasonably forecasting their load requirements. This will give utilities little incentive to accurately, rather than over, forecast load, because they will always be able to pass-on the costs of excess gas, no matter how expensive, to ratepayers

In its exceptions, CUB stated that, because the MERC unreasonably over-forecasted the amount of gas it needed to purchase during the February event, the Company purchased more gas than necessary, at highly inflated price. As a result, CUB continued to support its disallowance range[43]

h. Reference to the Record

MERC, Theodore T. Eidukas Direct, p. 32
MERC, Timothy C. Sexton Direct, pp. 23-24
MERC, Sarah R. Mead Direct, pp. 23-26
MERC, Sarah R. Mead Rebuttal, pp. 8-10.
CUB, Bradley Cebulko Direct, p. 54
CUB, Bradley Cebulko Surrebuttal, pp. 7, 16-17.
ALJ Report, pp. 46-66,
DOC, Exceptions to ALJ Report, pp. 56-59.
CUB, Exceptions to ALJ Report, p. 3

[43] CUB Exceptions to ALJ Report, at 3.

i. Staff Analysis

Staff notes that CUB has provided a range of recommendations; therefore, Staff has listed each one as a separate decision alternative.

j. Decision Alternatives

If the Commission does not adopt the ALJs findings related to load forecasting and storage, then the Commission may want to adopt one of the following decision alternatives:

- Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and; therefore, disallow recovery of recovery of $9,707,206. (DOC)
  Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and storage and; therefore, disallow recovery of recovery of $3,903,233. (CUB recommendation, high range)
- Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and storage and; therefore, disallow recovery of recovery of $1,649,837. (CUB recommendation, low range)

B. Curtailment

This issue is disputed between the Company, the Department and CUB. The Department recommended a $958,307 disallowance; whereas, CUB recommended a disallowance range between $902,791 to $4,165,683.

1. MERC Energy – Direct

MERC explained that its tariffs do not provide for price-based curtailment. Instead, the Company's tariffs establish a priority of service when operational and supply conditions, not economic factors, require service interruptions. MERC's practice is to curtail interruptible customers due to distribution system constraints, operational issues, or other limitations. For interruptible system sales customers, MERC may curtail based on available pipeline capacity and supply. MERC did not experience any operational or supply constraints that have supported the need to curtail its interruptible customers. MERC does not curtail customers based on pricing.

Even if MERC was permitted to curtail, it would have had to have declared a curtailment by 8:00 a.m. on Friday, February 12, 2021 for each of the following four days; however, the settled market prices were not known at that time and MERC had no reason to expect prices would reach the unprecedented level they did. Therefore, it would not have been possible for MERC to issue calls for curtailment based on pricing.

2. Department of Commerce – Direct

The Department stated that MERC could have planned to make curtailments over the four-day period and reduced their spot purchases; however, the decision to curtail would have needed to have been made early in the morning of February 12 based on anticipation of a price spike and, to reduce the ratable spot purchase for the entire four-day period, the curtailments could have been limited to the highest forecasted load day. However, since the magnitude of the price spike was unprecedented and not fully understood by February 12, the Department did not believe it was unreasonable for MERC to not plan on curtailing for the four-day period.

The Department stated that, with the benefit of the knowledge gained over the holiday weekend and in light of the extraordinary price spike, MERC could have planned curtailments to occur on February 17 and correspondingly reduced its February 16 spot purchases. For those reasons, the Department recommended a $958,307 disallowance that is calculated based on an assumed volume of planned curtailments equal to 50% of the usage of curtailment customers on February 17. This assumption reflects MERC planning a partial curtailment while reserving additional curtailment volume if needed.

3. Citizens Utility Board – Direct

CUB stated that MERC should have curtailed 50% of its interruptible load during the entirety of the Event. There was no operational or tariff restriction that would have prevented the utility from curtailing for economic reasons. CUB estimated that curtailing interruptible customers would have saved customers $4 million over the five-day event, and $820,000 on February 17. CUB disagreed with MERC's interpretation of the tariffs and the Company's claim that curtailments may only be triggered by available pipeline capacity and supply. The term "supply conditions" is not explicitly defined by MERC's tariffs. The tariffs do state that "[MERC] does not employ any technical or special terms which are unique to the application of any of its rate schedules, rules or regulations. All terms used by the Company are common terms in the industry. For clarification purposes such terms are defined in Rules and Regulations."[44]

CUB also disagreed with MERC's position that, even if MERC was permitted to curtail, it would have had to curtail by 8:00 a.m. Friday, February 12 for each of the following four days and the Company had no reason to expect prices to reach unprecedented levels. CUB stated that a reasonable utility would not have uncertainty about the terms of its tariffs. The gas procurement and senior management team should have absolute clarity on the issue. It appears there was uncertainty amongst MERC employees and if MERC could curtail for economic purposes. This lack of clarity on tariff terms is inexcusable and unreasonable.

Also, by Thursday, February 11, MERC knew that market prices were in the 98th percentile, and the worst of the storm had yet to occur. They knew that pipelines had issued warnings which suggests that the market was tightening and there could be reliability issues. Going into a four-day gas buying period with great uncertainty, a reasonable utility would have locked in the benefit to the system and customers by curtailing interruptible customers. It is a resource that has already been paid for by customers, the price is known, it reduces the customers exposure, and the utility can make a reasonable estimate of the level of compliance with its call.

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[44] See MERC Technical Terms and Abbreviations at https://www.minnesotaenergyresources.com/company/tariffs/terms.pdf.

CUB also noted that MERC's testimony is focused on what it knew leading into the four-day weekend and ignored its actions on Tuesday, February 16 (for gas delivery on Wednesday, February 17). By February 16, the Company knew that its load forecasts were consistently off and that the settled price of natural gas was greater than $150/Dth on NNG. Yet given all that information, the Company continued to significantly over-procure spot gas, not curtail interruptible customers, and not fully maximize its storage. These decisions display clear indifference for customer costs.

For these reasons, as shown in Table 2, CUB made an initial disallowance recommendation ranging from $820,184 to $4,083,076.

Table 2 – CUB's Initial Curtailment Disallowance Recommendation

MERC Disallowance Estimate Range	
Curtailment	**50% Interrupted**
2/13 – 2/17	$4,083,076
2/17 Only	$820,184

4. MERC – Rebuttal

MERC disagreed with the Department's conclusion that, based on the market price spike, the Company should have curtailed its interruptible customers on February 17. MERC's tariffs do not provide for price-based curtailment and such action is contrary to the approved interruptible rate structure.

MERC also disagreed with CUB's conclusions because, again, MERC's tariffs do not provide for price-based curtailment. Furthermore, even if MERC was permitted to curtail, it would have had to have declared a curtailment by 8:00 a.m. on Friday, February 12, 2021 for each of the following four days; however, the settled market prices were not known at that time, and MERC had no reason to expect prices would reach the unprecedented level they did. MERC added that it has not curtailed interruptible customers based on the price during previous market price spike events and, while such previous price spikes have been investigated in Commission investigation proceedings and through the AAA, neither the Commission nor any other participant has ever urged curtailments of interruptible customers based on gas prices.

MERC explained that, currently, there is no terms or conditions that would specify the price at which such curtailments would occur or the frequency or length of economic curtailments to which interruptible customers would be subject. While the frequency of such price-based curtailments would depend upon price, it is reasonable to expect that modifying interruptible service to include price-based curtailments would increase the frequency of curtailments. This would be a change to the character of the Company's interruptible rate offerings and would require either a reevaluation of the approved interruptible rate structure or the creation of a separate tariff class and rate that would be subject to price-based curtailments. Such a change would need to be evaluated in a rate case or other proceeding to be implemented, if at all, on a forward-looking basis.

For these reasons, MERC stated that the Department's and CUB's recommendations should be rejected.

5. Department of Commerce – Surrebuttal

The Department noted that MERC generally repeated its argument that they only curtail for capacity needs related to pipeline availability and not for economics. As a result, the Department reconfirmed its disallowance recommendation.

6. Citizens Utility Board – Surrebuttal

As shown in Table 3 and based on more current information, CUB updated its recommended disallowance range to $902,791 to $4,165,683.

Table 3 – CUB's Initial Curtailment Disallowance Recommendation

MERC Disallowance Estimate Range	
Curtailment	**50% Interrupted**
2/13 – 2/17	$4,165,683
2/17 Only	$902,791

7. ALJ Report

The ALJs found that:

> 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.

8. Exceptions to ALJ Report

a. Department Of Commerce

The Department noted that, instead of determining that MERC exercised prudence based on available information in deciding not to curtail for economic circumstances, the ALJs determined that the Company was incapable of making a reasoned determination to curtail for economics unless the Commission required it through express tariff provisions and benchmarks. The Department stated that the ALJs' analysis should be rejected.

It is the Commission and not OAH that has the expertise and authority to construe utilities' tariffs.[45] The ALJs' conclusion excuses MERC from acting prudently, stripping the Company of any requirement to exercise reasonable judgment and requiring the Commission to micromanage it with specific directives and triggers through detailed tariffs to address a wide-range of circumstances. This is not the place of tariffs. Instead, the prudence standard serves to ensure that MERC exercises good judgment without being told precisely when, how, and how much to do. Additionally, the ALJs overlooked that the type of specific tariff directives the ALJs appear to require for *economic* curtailment are not present for *operational* curtailment in MERC's interruptible customer tariffs. Instead of needing specific marching orders from the Commission, MERC has discretion under its interruptible tariffs to curtail for economic purposes, and prudence required curtailing on February 17 when it knew the conditions driving the extraordinary price spike of the previous weekend had not receded. Business as usual was not acceptable under these circumstances, and MERC had an obligation to use available tools to mitigate economic harm to ratepayers.

The ALJs found that "MERC Energy's tariffs do not contain established criteria for economic curtailments, such as the price or trigger for issuing such curtailments" and "[t]he absence of an express tariff provision relating to price-based curtailments means there are no parameters governing when MERC Energy could curtail customers for economic reasons . . . ."[46] The ALJs require specific benchmarks for economic curtailment, when no such parameters, structure, or benchmarks exist for curtailment for the purposes MERC invokes regularly, such as capacity constraints or reliability issues. Rather, the tariffs provide MERC with the authority to determine when curtailment is appropriate.

b. Citizens Utility Board

CUB disagreed with the ALJs conclusion that:

> 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." 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." Reading the document consistent with CUB's interpretation requires determining that a priority system exists for curtailments for operational or

[45] *See In re Minn. Power's Pet. for Interpretation of Terms & Conditions of Serv. to Verso Minn. Wisc. LLC*, MPUC Docket No. E-015/M-21-593, ORDER INTERPRETING ELECTRIC SERVICE AGREEMENT (Nov. 15, 2021) (eDocket No. 202111-179759-01) (finding Commission has authority to interpret provisions of electric service agreements under Minn. Stat. § 216B.02, .05, 08, .09).

[46] ALJ Report, Findings 279 and 281.

supply reasons, but that there is no specific priority of service when curtailments are called for other reasons.[47]

CUB did not argue that MERC's tariffs grant it "unfettered discretion" to exercise curtailments. CUB noted that MERC's tariffs, as a matter of fact, grant MERC *broad* discretion to exercise curtailments. MERC's tariffs provide that MERC customers taking service under various of MERC's interruptible tariffs "may be interrupted, curtailed or, discontinued at any time at the option of the Company in accordance with the provisions herein." Also, MERC's tariffs are silent on economic curtailments – the tariffs neither expressly permit nor prohibit curtailments for economic reasons. CUB acknowledged that the tariffs include a "priority of service" for "when operational and supply conditions require service interruptions" and disagreed with the Judges suggestion that the absence of a separate priority of service for "other reasons" somehow limits MERC's broad discretion to call for curtailments "in accordance with" the tariffs.

Reading the tariff consistent with the Judges interpretation requires determining that the tariff permits curtailments when operational or supply conditions exist other than dramatically increasing costs of available gas supply. Such an exclusion is not written into the tariff. It is inconsistent and illogical of the Judges to interpret the tariff so restrictively while simultaneously dismissing CUB's broader interpretation as flawed. Moreover, the underlying factors that led to quickly rising cost of available gas supply clearly fall within the term "operational and supply conditions."

9. Reference to the Record

MERC, Eidukas Direct, pp. 27-31.
MERC, Eidukas Rebuttal, pp. 21-36.
DOC, King Direct, pp. 96-101.
DOC, King Surrebuttal, pp. 5-7.
CUB, Cebulko Direct, pp. 6, 29.
CUB, Cebulko Surrebuttal, pp. 5-6.
CUB, Nelson Surrebuttal, pp. 4, 31-35.
ALJ Report, pp. 59-64, Findings 259-282
DOC, Exceptions to ALJ Report, pp. 40-42, 46-49.
CUB, Exceptions to ALJ Report, pp. 5-7.

10. Decision Alternatives

If the Commission does not adopt the ALJs findings in related to curtailment, then the Commission may want to adopt one or more of the following decision alternatives:

- Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and; therefore, disallow recovery of recovery of $958,307. (DOC)

[47] ALJ Report, page 61.

- Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and storage and; therefore, disallow recovery of recovery of $4,165,683. (CUB recommendation, high range)
- Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and storage and; therefore, disallow recovery of recovery of $902,791. (CUB recommendation, low range)

C. Financial Hedging

This issue is disputed between the Company and the OAG. The OAG's primary recommendation was that MERC's full $64,975,882 be disallowed. However, as an alternative, the OAG also recommended that MERC's disallowance be no less than $7.0 million to $8.8 million.

1. MERC – Direct

MERC noted that it has developed and implemented a hedging strategy that targets price protection for 60% of normal winter volumes – 30% through physical storage and 30% through financial instruments (10% futures and 20% options). MERC hedges winter months with these contracts executed in the preceding summer months. Specific to 2021, MERC had purchased all winter (November 2020-March 2021) financial contracts by the end of October 2020. MERC hedges against NYMEX volatility, offering protection from monthly market volatility.

Hedging is designed to reduce MERC's month-to-month price swings in the PGA and provide reasonable cost for blended gas supplies. Ideally, the PGA would have less price volatility than the appropriate market index price volatility, but it is not expected that the PGA would be lower than the market index price over time. MERC's goal is to have a balanced approach that provides price protection for customers while also allowing MERC to take advantage of lower-than-expected market prices. The more a company hedges, the higher the reduction of volatility. However, as one hedges more, you risk the chance of over-hedging (i.e., 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, and the less opportunity there is to participate in a falling gas market, you risk ultimately increasing customers' gas costs.

MERC stated that it contracted for call options during the 2020-2021 winter period. The benefit of call options 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 with call options ensures the supply will be there on a cold day or during peak days. These options are typically required to be called upon for an entire trading window. 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.

2. Office of the Attorney General – Direct Testimony

The OAG noted that all four regulated gas utilities have engaged in physical or financial hedging in one form or another. Physical hedging refers to actions like purchasing natural gas over the summer and physically storing it for later use during the winter. Financial hedging often involves derivatives, such as options and futures contracts.

The OAG explained that utilities use two different types of call options:

- Call options give the owner the right, but not the obligation, to buy a specific amount of the underlying commodity at a specific price (the option's strike price) for a limited period of time (until the expiration date). The option seller is paid a premium for agreeing to deliver the commodity (or its financial equivalent) under the contract terms. Call options with strike prices below the current market price are "in the money." If the strike price is near or equal to the market price, the options are considered "at the money," and if it is above the market price, they're "out of the money".
- The utilities also discuss a different type of "call option" that does not specify the price at which the buyer can purchase natural gas. Some of the utilities describe the ability to "call" on gas supply that has been prearranged to be provided on 24 hours' notice at a floating, index-based price (i.e., with no upper limit, or ceiling on the price).

The OAG explained that utilities generally refer to the second type as "swing" contracts and that these contracts are purchased in the CME Group's (CME) exchange.

The OAG noted that utilities stated that "[t]ypically, daily call options would be purchased prior to the beginning of winter and would only cover the winter season."[48] Some of the utilities did purchase call options that cap the maximum price in the *monthly* market. That is, they purchased some options that protect against price spikes for a month-long supply of gas, but do not protect against price spikes for short-term gas supply during the middle of the month. These options may be described as monthly, FOM contracts and do not fully hedge against price spikes such as the one that occurred in February 2021. Since it is possible that some of the utilities have traded them in the past, but not during February 2021 and the OAG was unable to find price data for any of the daily, weekly, or short-term options for each February 2021 day, the OAG requested that utilities, in rebuttal, include a discussion of the extent to which they have traded options like the daily, weekly, and short-term options in the last 15 years.

Since most, if not all, of CME's options are tied to Henry Hub, rather than hubs like Demarc and Ventura, it is unlikely that the daily, weekly, or short-term options would have precisely offset all of the cost but, because they are tied to shorter time frames (daily/weekly vs. monthly) and would therefore be more responsive to short-term price spikes, they may have offset more cost relative to the monthly Henry Hub options.

[48] Grizzle Direct at Schedule 2, p. 35 of 101.

While prices were in well in excess of $100 at Demarc and Ventura for the duration of the long weekend, they were only $6 at Henry Hub; therefore, if the utilities had negotiated Henry Hub pricing, rather than Demarc and Ventura, to be the basis for their swing purchases, it may have been easier to hedge against the price spike. However, since, the OAG was unaware of any exchange-traded hedges that would have fully offset the price spike cost that occurred at places like Demarc and Ventura, the OAG requested that, in rebuttal, that the utilities discuss options specific to trading hubs like Demarc and Ventura. The discussion should include the extent to which they have traded options specific to trading hubs like Demarc and Ventura in the last 15 years.

The OAG added that exchange-traded puts and calls used for hedges like collars are available to all market participants. Over-the-counter (OTC) hedges are, almost by definition, often individually negotiated between two specific counterparties, so it is not clear whether they would be available to all four of the utilities.

The OAG pointed out that during the February Event, while natural gas prices increased by over 100 times, hedges only increased in value by approximately 20x to 30x. So, for instance, a 20x increase in the value of a hedge would offset 1/5, or 20%, of a 100x underlying price increase. From the morning of February 8, 2021, until early afternoon of February 10, 2021, call options were priced at $30 and, during the night of Wednesday February 17, they were valued at $650. Thus, if a company had invested $6.5 million at a $30 price and sold at the $650 price, it would have generated a $134 million profit. On the basis of the specific hedges that increased from $30 to $650, the Commission should treat that 21.67x[49] increase as the maximum amount that it could disallow.

The OAG stated that a reasonable and prudent utility would have added a hedge during the week prior to the price spike for these reasons:

- The particularly cold weather forecast in Texas from both utility and third-party meteorologists.
- Reports of “the possibility of freeze-offs starting February 8th and stronger competition from traders in different regions for gas supplies.”[50]
- “supply loss[es that] began as early as February 7, 2021.”[51]
- SOL notices from the pipelines.

If the utilities had acted early in the week when things started looking concerning, they may have been able to open the hedge for approximately $30 to $35 on February 8-9, 2021. If they had waited until later in the week, they may have been able to open it for around $45 on February 11, 2021. In fact, the weighted average price, including the relatively high prices paid during the afternoon of Friday, February 12, 2021, during the week prior to the event was

[49] $650/$30 = 21.67.

[50] Reed Direct, p. 69.

[51] See Schedule BPL-D-10 (Joint Gas Utilities’ response to DOC Information Request 29) and Smead Direct at Schedule 5, p. 2.

approximately $46. Given this information, the OAG believes a $35-$45 range would have been reasonable. Had utilities purchased at $35 (instead of $30) and sold at $500 instead of $650, they would have captured about two thirds of upward move which would have offset 14.29% of a 100x price increase that, for MERC, it would represent $9.4 million. If they had bought at $45 and sold at $500, they would have captured about half of upward move that, for MERC, it would represent $7.0 million. Since the OAG did not know whether any of the utilities' increase was higher or lower than 100x, the OAG recommended that, in rebuttal, each utility provide its best increase estimate. Thus, the OAG concluded that a minimum disallowance for MERC would be in the $7.0-$9.4 million range.

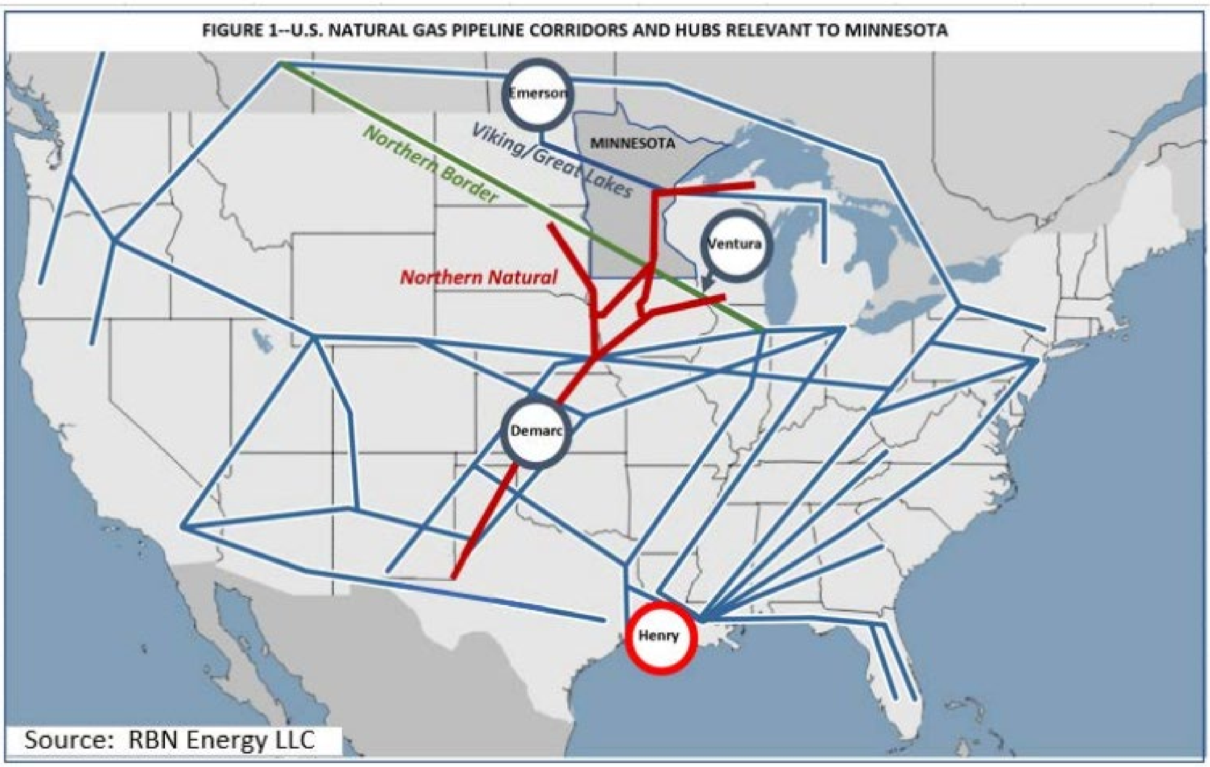
3. MERC – Rebuttal

MERC stated that market participants, including the utilities' supply managers, who engage in hedging deals related to natural gas supplies are extremely sophisticated. Hedging instruments are not simple and require an extensive knowledge of the natural gas marketplace.

MERC added that the OAG's testimony contains unwarranted and highly speculative assumptions, lacks supporting facts, and illustrates a limited and at times incorrect understanding of the market for hedging instruments. The OAG discussed tools that have no bearing on the gas-cost experience in Minnesota and potential tools that might have been helpful if they existed; however, the OAG acknowledged that it does not know whether any were available and instead requested that the utilities, in rebuttal, provide facts to disprove those assumptions that. For example, the OAG assumed that speculation in March natural gas options could have yielded huge speculative profits to offset gas-price increases that occurred in February, with no evidence that investing in such options would have been any more than a blind bet with customers' money

The OAG conflates "financial" hedging with "physical" hedging. It purports to discuss financial hedging, rather than physical hedging, but describes physical hedging at various places (such as in tying price caps levels and price commitments to the physical levels of supply required). The conflating of two separate concepts makes it difficult to understand which markets, prices, and products are being addressed. The OAG also conflates "calls" and "puts" on an options exchange with bilateral deals with suppliers relative to the actual supply points. The calls and puts OAG discusses are the purchase and sale of options to trade gas futures contracts at a specified price on the CME at Henry Hub in Louisiana. As shown in Figure 1, MERC's relevant supply points are not at Henry but at Demarc and at Ventura which is where the majority of the gas is received. Any meaningful hedging strategy depends on achieving price protection at Demarc and Ventura, not Henry. Therefore, many of the OAG observations grounded at Henry have no connection to MERC's decisions. MERC's spike in market gas costs was caused by market conditions that affected pricing at its supply hubs, not at Henry.

Figure 1 – U.S. Natural Gas Pipeline Corridors and Hubs Relevant to MN



Henry's geographic and economic separateness is demonstrated by the stark difference in prices at Demarc and Ventura, versus Henry. For example, the price for cash purchases of gas at Demarc was as much as $223.12/Dth higher than Henry's, and Ventura's was as much as $171.37 higher. Henry's pricing is meaningless in evaluating MERC's high prices. The OAG acknowledged this disconnect: "Since most, if not all, of CME Group's options are tied to Henry Hub, rather than hubs like Demarc and Ventura, it is not likely that the daily, weekly, or short-term options would have precisely offset all of the cost".[52]

The OAG also used Xcel Energy's indexed purchases as further evidence of Henry's relevance. However, although gas-purchase contracts often reference Henry, they typically include an additional increment to reflect the basis to wherever the buyer actually takes title to the gas. MERC is supplied from Kansas, Iowa, and Minnesota,[53] with gas that comes primarily from Texas, Oklahoma, North Dakota, and Canada. Thus, purchases that use Henry references in their pricing incorporate an increment to account for the price difference between the purchase points and Henry. Furthermore, MERC noted that sellers who have committed to supply gas on call, as is the case in the swing contracts, would never agree to forego the market value of that gas at those points. Also, if a supplier were to accept such an arrangement, it would constitute a commodity "position" for purposes of the Commodity Futures Trading Commission (CFTC) rules, placing substantial pressure on the supplier's credit. The OAG did not cite a single example of a supplier offering such an arrangement.

[52] Lebens Direct, page 8, lines 17-19.

[53] Minnesota being the border crossing from Emerson, Manitoba.

Regarding the use of collars, all the option examples the OAG uses are CME options to buy futures contracts at Henry. Not only are Henry transactions irrelevant, but such options can only be exercised to buy a futures contract before the month to which the futures contract would apply. They cannot be exercised in the middle of a month (e.g., February 8 for February supply) when an unanticipated spike in gas cost takes place after the start of the month. Also, the floor price, or put, carries with it the obligation to buy the subject futures contract even if the floor price is well above the current market price. This can force the buyer to take excess gas that may have to be disposed of at (sometime significantly) lower prices which could lead to substantial losses that would be borne by customers. If engaging in such collars were business as usual, at a level to accommodate all of the utilities' swing gas, these additional costs would happen frequently over many years, leading to very large cumulative ratepayer costs, and still not protect against a totally unprecedented event such as Winter Storm Uri. The OAG's reference to these collars as "cost-free" does not take into account the obligation to take put gas at uneconomic prices, and then to dispose of excess gas at low end-of-season market prices. If the transaction is with a single counterparty who both sells the call and the buys a put, the counterparty will not assume the risk of being capped at a price that may end up being well below market, without gaining the security of a floor that may end up being higher than market. Therefore, to compensate for the unbalanced price risk, the seller will require either a significant option fee or require that the volumes of gas subject to the put to be higher than the volumes subject to the call volume. If call and put transactions are made with different counterparties, both transactions will require option fees, one *from* the utility and one *to* the utility. The collar is only cost-free if these fees are equal. The seller of the call option will require an increasingly high fee for reductions in the cap price, and the buyer of the put option will not pay fees equal to the call fees unless the put strike price (the price at which the futures contract can be sold to the buyer) is high enough to represent significant value over the likely market. Thus, to be protected on the high side of prices, the utility necessarily runs the risk of being forced to take overpriced gas for the life of the agreement, which would lead to higher costs for customers over a longer period of time. This factor exacerbates the damage caused by having to take put gas when it is higher than the market. Furthermore, the OAG's opinion that the puts should not exceed the quantity of gas the utility expects to consume demonstrates the problems with its costless collar testimony because, at the point when options would need to be negotiated, in advance of the heating season, the utility does not know how much gas its customers will consume. Thus, the OAG's advice to match puts to the quantity of gas that will actually be consumed is impractical.

MERC noted that the OAG acknowledged a lack of awareness regarding whether the products advocated in support of their primary recommended disallowance even exist; therefore, the OAG also offers an alternative $7,017,395 to $9,427,954 disallowance for MERC.

4. Office of the Attorney General – Surrebuttal

The OAG agreed that there was limited liquidity before and during the February Event; however, the OAG partially attributed the limited liquidity to the utilities not using them. Had the utilities been prudently hedging or adjusting hedges in response to market conditions, the hedges would have been more liquid. Additionally, the utilities had only limited incentive to pursue stable gas prices.

Regarding MERC, the OAG stated that the Company did not use *any* of its approved 26 Bcf of financial hedging. Furthermore, MERC was not restricted from adjusting hedges in response to changing market conditions nor did the Commission Order dictate whether MERC should use daily, monthly, or seasonal hedges. MERC was free to make a wide variety of decisions to achieve things like its explanation that "[h]edging winter gas supply prices stands to protect the Company's customers from the most severe price spikes during the coldest and, thus highest consumption, periods of the year."[54] But there is one area that is not entirely clear regarding the types of hedges that MERC was allowed to use: MERC did propose to use futures contracts but, other than a general approval of MERC's proposal, the Commission's Order does not specifically approve them. MERC explained in its proposal that a "futures contract is used to lock-in the price of natural gas for customers."[55] If the Commission finds that it approved MERC's request to use futures contracts, it is worth noting that a swing future is one type of futures contract. Futures contracts function similarly to a collar that has the same the ceiling price and floor price. Also, the Commission Order did not restrict MERC from requesting to incorporate hedging costs into its base rates nor did it restrict the Company from requesting to incorporate hedging costs into other mechanisms like riders or trackers. Therefore, MERC's could have spent more than the approved $6.5 million on financial hedging and requested to recover it through base rates or through a rider or tracker. The OAG did acknowledge that there was no guarantee that the Commission would approve such a request.

The OAG added that, given enough time to plan ahead in order to achieve a goal to maintain a reasonable range of gas prices, is it possible that a utility could have directly negotiated with another party to mimic a swing future using an OTC-type contract, including a swing supply with a built-in price ceiling and price floor.

The OAG disagreed with MERC's comment that "it is unreasonable to assume that anyone in the market would, or should, have taken steps in advance to hedge (i.e., anticipate) an unanticipated price risk".[56] Hedging should generally be done in advance. One of the benefits of hedging is that one need not predict or anticipate the exact time or amount of an unanticipated commodity price risk. One only needs to place an appropriate hedge ahead of time so that it is there when needed to maintain an expected range of commodity prices and avoid extreme prices.

The OAG stated that Purchased Gas Adjustment clauses were introduced so utilities could pass the commodity cost of gas on to their customers instead of retaining the financial risk of price spikes as they did previously. This meant that the risk of a price spike shifted away from shareholders and toward customers. A disallowance (or an equivalent alternative) in this would encourage utilities to avoid speculating that prices may remain in an expected range or

[54] MERC Variance Petition at 7.

[55] MERC Variance Petition at 8.

[56] Grizzle Rebuttal at 52, pp. 1-5.

decrease and would encourage utilities to pursue better-targeted hedges similar to (1) swing futures, (2) swing supply with ceiling and floor prices, (3) OTC-type contracts, or (3) other similar arrangements to maintain an expected range of prices.

The OAG ended by reasserting its disallowance recommendations.

5. ALJ Report

The ALJs found that:

> 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 prudency 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.
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> 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.

6. Exceptions to ALJ Report

a. Office of the Attorney General

The OAG stated that adopting the ALJs' Report would pass-through costs that were incurred as the result of unreasonable and imprudent decisions and impose a significant burden on captive ratepayers, including residents and small businesses, who are already navigating a difficult economy. Furthermore, allowing the utilities to recover imprudently incurred costs could have longer-term consequences for ratepayers because they will have no reason to respond differently to future price spikes if they assume, as they did during the February Event, that they will be able to automatically recover any costs they incur.

The OAG stated that the ALJ Report should be rejected because they are based on (1) a misapplication of the burden of proof; (2) a misunderstanding of the fundamental nature of hedging; (3) a misapplication of past Commission orders; and (4) errors and omissions with respect to the availability of certain financial products. While the ALJ Report correctly state the truism that the utilities should bear the burden in these proceedings, they fail to even acknowledge, much less apply, important articulations of that burden made by the Commission and the Supreme Court. For example, the Supreme Court has stated that:

> By merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses.[57]

The Commission has also provided further guidance noting that "[a]llowing a utility to recover its imprudently incurred costs simply because public agencies or other intervenors are unable to precisely identify which imprudent actions caused which costs would not result in just and reasonable rates."[58]

The ALJ Report fails to provide any of the salient detail about the implications of a utility "merely showing that it has incurred . . . expenses" or acknowledge the absence of an obligation of intervenors to "precisely identify which imprudent actions caused which costs."

Conduct does not need to violate a Commission order to be imprudent, and relying on the absence of such a violation to find prudence would create a presumption that any utility decisions not specifically governed by an existing order are prudent. Such a presumption would shift the burden from the utilities to act prudently to the Commission to preemptively dictate what specific actions the utilities should take in any conceivable situation.

MERC notes that the Company generally does its hedging "in the preceding summer months".[59] It is contradictory to suggest that the OAG's proposed hedging strategies could not be implemented because such action needed to have been prior to the February Event, when that is precisely when the Utilities conduct their hedging. Additionally, the Utilities are not restricted from adjusting hedges or locking-in prices in response to market conditions like forecasted infrastructure freeze-offs or SOL notices. As hedging is generally accomplished prior to a pricing event and hedging strategies can be adjusted in response to new information, the ALJ Report finding that the OAG's hedging recommendations were not a plausible strategy should be rejected.

The ALJ Report also mischaracterizes the nature of Commission orders that approved rule variances in order to allow for special cost recovery of hedging costs in a manner not normally permitted by Minnesota Rules. The ALJ Report inaccurately portrays the Commission as the arbiter of what operational hedging decisions utilities are allowed to make. The orders cited by the ALJ Report, however, have a much narrower purpose: they set conditions limiting the amount of hedging costs that can be recovered through the Purchased Gas Adjustment (PGA). Such variances are necessary because, under the Rules, these hedging costs are not normally recoverable in this manner. Effectively, the ALJ Report asks the Commission to conclude that,

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

[58] *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754, ORDER FINDING IMPRUDENCE, DENYING RETURN ON COST OVERRUNS, AND ESTABLISHING LCM/EPU ALLOCATION FOR RATEMAKING PURPOSES at 13 (May 8, 2015) [hereinafter Monticello Order"].

[59] ALJ Report, Finding 152.

by granting a variance to the PGA and giving the utilities special recovery outside of the normal ratemaking process, the Commission has taken on the responsibility of making operational, day-to-day hedging decisions for the utilities. Utility employees, not the Commission, are responsible for operating the utilities. The Commission should not grant the utilities the benefit of special cost recovery, and then allow them to use that privilege as a shield to preclude review of the prudence of their hedging practices and determinations.
A closer reading of the various PGA Orders makes clear that the Commission did not believe that those orders were the final word on the prudence of the Utilities' hedging strategies. In fact, the PGA Orders contemplate that some of the hedging covered by the variance could turn out to be imprudent. Specifically, in at least one case, the Commission's Order expressly limits PGA recovery to prudent hedging.[60] This qualifier would be unnecessary if the Commission were approving the hedging strategy set forth in the utility's filing. Nowhere do the PGA Orders state that additional hedging costs would be unrecoverable through other mechanisms, such as base rates.[61]

Also, the ALJ Report makes a variety of errors and omissions which provides further support for the Commission to disregard the Reports' findings and recommendations with respect to hedging and, in order to protect ratepayers, instead make its own determinations. The MERC Report that "[a]vailable hedging tools are monthly-oriented similar to baseload purchases."[62] The MERC Report also faults the OAG for failing to identify OTC products that could have been used at Demarc or Ventura.[63] This ignores the fact that OTC hedges are, almost by definition, often individually negotiated between two specific counterparties and non-exchange-traded investments are not usually available for public viewing. Accordingly, the utilities are uniquely positioned to identify and explain such products. This type of information disparity is why the burden is always on the utility to prove prudence, and not on any intervenor to show imprudence. The ALJ Report makes no findings that such products are not potentially available to the Utilities. Holding this perceived ambiguity against ratepayers would be a burden shift and would impermissibly fail to resolve all doubt in favor of ratepayers.

The OAG stated that continued to recommend that its proposed disallowances be adopted.

7. Reference to the Record

MERC, Mead Direct, pp. 33-36.
MERC, Eidukas Rebuttal, pp. 11-17.
MERC, Sexton Rebuttal, pp. 12-27.
MERC, Smead Rebuttal, all.

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[60] See MERC PGA Order, attach. at 12 (stating that "the Commission would maintain its authority to disallow imprudent or unreasonable transactions" if it later concludes that MERC acted in an unreasonable manner).

[61] See, e.g., Xcel PGA Order at ¶ 4 (limiting costs that Xcel can recover "through the Purchased Gas Adjustment" (emphasis added)).

[62] ALJ Report, Finding 153.

[63] ALJ Report, Finding 165.

OAG, Lebens Direct, all.
OAG, Lebens Surrebuttal, all.
ALJ Report, pp. 33-41, Findings 148-187.
OAG, Exceptions to ALJ Report, all.
OAG, Initial Brief, all

8. Staff Analysis

Staff notes that the OAG's hedging secondary recommendation provided a disallowance range; however, there is disagreement regarding what the correct range should be. The OAG has indicated that, for MERC, the range is between $7 million and $8.8 million.[64] However, in rebuttal, the Company indicated that range is $7,017,395 to $9,427,954.[65]

Staff agrees that the correct low range is $7 million; however, using the "OAG's formula" that uses 14.29% for the high number calculation, Staff calculates the high number to be $9,285,054.[66]

As a result, Staff has included all these amounts as possible decision alternatives.

9. Decision Alternatives

If the Commission does not adopt the ALJs findings in related to financial hedging, then the Commission may want to adopt one or more of the following decision alternatives:

- Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of the full $64,975,882. (OAG primary recommendation)
- Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of $8.8 million. (OAG recommendation, high range)
- Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery $7.0 million. (OAG recommendation, low range)
- Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery $9,427,954. (MERC's calculation of OAG recommendation, high range)
- Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery $7,017,395. (MERC's calculation of OAG recommendation, low range)

[64] OAG Initial Brief, p. 13, footnotes 58 and 59.

[65] Eidukas Rebuttal, p. 17

[66] $64,975,882 x 14.29% = $9,285,054.

- Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of $9,285,054. (Staff's calculation of OAG recommendation, high range)

VII. Staff Analysis

The main issue in this case is whether MERC's actions during the February Event were prudent *based on information known at the time*. This does not mean that every action the Company took had to be "perfect". An innate characteristic of running a business is that, after decisions are made, they may result in the "best" possible outcome. However, just because the best possible outcome was not achieved, it does not mean that the Company acted imprudently.

The ALJ has recommended that no disallowances be made in this proceeding so, if the Commission orders any disallowance, then the Commission may want to order MERC to, within 60 days, make a compliance filing that updates the remaining recovery amount and also updates the recovery factors for the remainder of 27-month recovery period and delegate approval to the Executive Secretary.

Also, since recovery of extraordinary costs is volumetric and recovery factors are based on sales forecasts, Staff considers it likely that, at the end of the recovery period, a remaining balance that will require a true-up will exist. For that reason, the Commission may want to order MERC to incorporate any remaining true-up into its next annual AAA report following the end of the 27-month period.

VIII. Decision Alternatives

[Commissioners should select either Decision Option 2 or decide among the disallowance recommendations in Decision Options 3 through 14].

<u>ALJs' Report</u>

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

AND

<u>Prudency and Recoverability</u>

2. Find that the extraordinary gas costs incurred by MERC to serve its customers during the February Event were prudently incurred and, therefore, it is just and reasonable to recover those costs from customers. (MERC)

OR (if decision option 2 is not selected, select one or more of the following)

Load Forecasting and Storage

3. Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and; therefore, disallow recovery of recovery of $9,707,206. (DOC) or

4. Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and storage and; therefore, disallow recovery of recovery of $3,903,233. (CUB recommendation, high range) or

5. Find that MERC did not meet its burden to prove it acted prudently with respect to load forecasting and storage and; therefore, disallow recovery of recovery of $1,649,837. (CUB recommendation, low range)

Curtailment

6. Find that MERC did not meet its burden to prove it acted prudently with respect to curtailment and; therefore, disallow recovery of recovery of $958,307. (DOC) or

7. Find that MERC did not meet its burden to prove it acted prudently with respect to curtailment; therefore, disallow recovery of recovery of $4,165,683. (CUB recommendation, high range) or

8. Find that MERC did not meet its burden to prove it acted prudently with respect to curtailment and; therefore, disallow recovery of recovery of $902,791. (CUB recommendation, low range)

Hedging

9. Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of the full $64,975,882. (OAG primary recommendation) or

10. Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of $8.8 million. (MERC's calculation of OAG recommendation, high range) or

11. Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of $7.0 million. (MERC's calculation of OAG recommendation, low range) or

12. Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of the full $9,427,954. (MERC's calculation of OAG recommendation, high range) or

13. Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of the full $7,017,395. (MERC's calculation of OAG recommendation, low range) or

14. Find that MERC did not meet its burden to prove it acted prudently with respect to financial hedging and; therefore, disallow recovery of recovery of $9,285,054. (Staff's calculation of OAG recommendation, high range)

<u>Compliance Filing</u>

15. Order MERC to, within 60 days, make a compliance filing that updates the remaining recovery amount and also updates the recovery factors for the remainder of 27-month recovery period. Delegate approval of this compliance filing to the Executive Secretary. (Staff)

<u>Final True-Up</u>

16. Order MERC to incorporate any remaining true-up into its next annual AAA report following the end of the 27-month period. (Staff)