Direct Testimony and Schedules
Timothy C. Sexton

Before the Office of Administrative Hearings
600 North Robert Street
Saint Paul, Minnesota 55101

For the Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
Saint Paul, Minnesota 55101

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

MPUC Docket No. G011/M-21-611
OAH Docket No. 71-2500-37763
Exhibit _____ (TCS-D)

Independent Evaluation

October 22, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy C. Sexton. My business address is 19500 State HWY 249, Suite 245, Houston, Texas 77070.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of Gas Supply Consulting, Inc., which I will refer to as "GSC."

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Minnesota Energy Resources Corporation ("MERC").

Q. PLEASE DESCRIBE YOUR EDUCATION AND YOUR RELEVANT EXPERIENCE.

A. I received a Bachelor of Science degree in Civil Engineering from the University of Texas in May 1989 and a Master of Business Administration from the University of Houston in August 1993. I am a licensed professional engineer in the state of Texas. I have been actively involved in the natural gas business for over 30 years. I began my career at United Gas Pipeline Company (currently Gulf South Pipeline Company) in various engineering, operations, planning, and marketing positions, culminating in the position of Regional Manager of Supply Services. I have been with GSC since June 1994. At GSC, I held the position of

Associate from 1994 through 2006 and Vice President from 2006 through 2011. I have been the President of GSC since January 2012.

Q. PLEASE DESCRIBE GSC'S BUSINESS.

A. GSC provides consulting services for clients in various segments of the natural gas industry. Our clients include local distribution companies, electric power generators, LNG exporters and importers, natural gas end-users, natural gas producers, midstream transporters, customer groups, and other participants in the natural gas industry.

Q. WHAT TYPES OF CONSULTING SERVICES DOES GSC TYPICALLY PROVIDE FOR ITS CLIENTS?

A. Some of the services that GSC provides for its clients include:

- gas supply planning, including the design of service and supply portfolios.
- negotiating natural gas transportation, storage, and balancing services.
- negotiating gas supply agreements.
- regulatory support and evaluation of pipeline operations and rate filings.
- evaluating pipeline expansion project alternatives.
- energy purchasing audits.
- evaluating service alternatives, including opportunities for service diversification.
- designing and implementing supply-related risk management programs.

- developing comparative economic analyses for service alternatives.
- evaluating the optimization of contracted supplies and services.
- evaluating adequacy of pipeline facilities to meet demand requirements.
- analyzing natural gas pipeline contingency and reliability.
- preparing preliminary pipeline engineering evaluations and cost estimates.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION ("COMMISSION")?

A. Yes. I provided testimony on behalf of MERC in Docket No. G011/M-15-895.

Q. HAVE YOU PROVIDED TESTIMONY IN ANY OTHER FEDERAL OR STATE REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony on the federal level at the Federal Energy Regulatory Commission ("FERC") as well as at various state regulatory proceedings. My CV, attached as Exhibit ___ (TCS-D), Schedule 1, provides a summary of testimony that I have provided in previous regulatory proceedings.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an evaluation of the reasonableness and prudence of MERC's actions and decisions before and during the

unprecedented spike in natural gas prices that occurred in February 2021 due to increased demand for natural gas due to cold weather across much of the United States and supply disruptions (the "February Event"). Based on my analysis and my experience in the natural gas business, I am providing my evaluation and professional conclusions with respect to the following issues:

1. MERC's gas procurement process, service and supply portfolio, and use of geographic diversity in its portfolio of services to acquire natural gas supplies during the February Event.
2. MERC's use of storage during the February Event.
3. MERC's use of daily index versus fixed-price supply during the February Event.
4. MERC's response to weather information available prior to the February Event.

Q. WHAT SCHEDULES ARE YOU SPONSORING AS PART OF YOUR TESTIMONY?

A. I am sponsoring the following schedules:

- Exhibit ___ (TCS-D), Schedule 1: Curriculum Vitae of Timothy C. Sexton.
- Exhibit ___ (TCS-D), Schedule 2: MERC Supply / Demand Planning During February Event
- Exhibit ___ (TCS-D), Schedule 3: Alberta Weather Data vs US Midwest Gas Prices

- Exhibit ___ (TCS-D), Schedule 4: Map of Northern Natural Gas Markat Area and MERC Receipt Points

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

III. BACKGROUND

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide a brief overview of the February Event and extraordinary costs as defined by the Commission. I also provide a summary of my conclusions. I then summarize MERC's two service areas, and I introduce the interstate natural gas transmission lines by which MERC obtains natural gas to serve its customers. My testimony will then move into the following section, where I discuss in more detail the particular service area impacted by the February Event.

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE FEBRUARY EVENT AND EXTRAORDINARY COSTS AS DEFINED FOR THE PURPOSES OF THIS PROCEEDING.

A. In its August 30, 2021 Order Granting Variances and Authorizing Modified Cost Recovery Subject to Prudence Review, and Notice of and Order for Hearing, the Commission defined "the February Event" as February 13–17, 2021. As also stated in its Order, for the purpose of these dockets, the Commission has defined "extraordinary costs" as the margin between $20/Dekatherm ("Dth") and the actual daily price experienced by the utilities, including MERC, during the February Event.

Q. BASED ON YOUR REVIEW OF MERC'S NATURAL GAS PURCHASING DURING THE FEBRUARY EVENT, DID MERC REACT REASONABLY TO FORECASTED NATURAL GAS DEMAND, AVAILABLE WEATHER DATA, AND INDUSTRY-WIDE NATURAL GAS SUPPLY LOSSES DURING THE FEBRUARY EVENT?

A. Yes. MERC was successful in reasonably and prudently arranging for sufficient natural gas supply to meet its customer needs during the unprecedented February Event.

Q. PLEASE DESCRIBE MERC'S OPERATIONS IN MINNESOTA.

A. MERC operates two distinct Purchased Gas Adjustment ("PGA") areas within the state of Minnesota to provide natural gas service to its customers. These two PGA areas are Minnesota Energy Resources Corporation-Consolidated ("MERC-

Consolidated") and Minnesota Energy Resources Corporation-NNG ("MERC-NNG").

MERC-Consolidated PGA service areas are directly connected[1] to the Viking Gas Transmission ("Viking"), Great Lakes Gas Transmission ("Great Lakes"), and Centra Pipelines Minnesota Inc. ("CPMI") pipeline systems.

MERC-NNG PGA service areas are physically connected[1] to and receive gas via delivery from the Northern Natural Gas Company ("Northern") pipeline system.

IV. MERC-CONSOLIDATED PGA AREA NATURAL GAS SOURCING

Q. HOW IS GAS PHYSICALLY SOURCED TO MERC'S CONSOLIDATED PGA AREA MARKETS CONNECTED TO THE VIKING AND GREAT LAKES PIPELINE SYSTEMS?

A. MERC 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

[1] MERC has interconnections with the pipeline system operators identified for each of its PGA areas from which natural gas is delivered to MERC for distribution to MERC's end-use customers.

and Great Lakes to MERC-Consolidated PGA area markets directly connected to Viking and Great Lakes.

Q. HOW IS GAS PHYSICALLY SOURCED TO MERC'S CONSOLIDATED PGA AREA MARKETS CONNECTED TO THE CPMI PIPELINE SYSTEM?

A. 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 to serve MERC-Consolidated PGA area markets on CPMI. Natural gas supplies are acquired by MERC into the CTHI system at a CTHI interconnect with the TransCanada Pipeline at Spruce, Manitoba. This gas is then transported on CTHI to CPMI at the US/Canadian border at International Falls, Minnesota. Finally, after crossing the border, the gas is transported on CPMI from International Falls to MERC-Consolidated PGA area markets directly connected to CPMI.

Q. WITH RESPECT TO ITS MERC-CONSOLIDATED PGA AREA MARKETS, DID MERC INCUR ANY EXTRAORDINARY COSTS DURING THE FEBRUARY EVENT?

A. No. As defined in this docket, MERC did not incur any extraordinary costs during the February Event within its MERC-Consolidated PGA area markets.

Q. WHY WAS THE MERC-CONSOLIDATED PGA AREA ABLE TO AVOID EXTRAORDINARY COSTS DURING THE FEBRUARY EVENT?

A. As noted above, MERC-Consolidated PGA area markets are connected to and receive natural gas supplies from Viking, Great Lakes and CPMI. As a result, natural gas supply costs into the MERC-Consolidated PGA area are dependent upon the cost of natural gas into these three pipelines. As discussed in detail above, MERC obtains supply into Viking and Great Lakes at the US/Canadian border at Emerson, Manitoba and into CPMI via CTHI's interconnect with the TransCanada Pipeline at Spruce, Manitoba. During the February Event, natural gas market prices at Emerson, Manitoba and Spruce, Manitoba did not experience price spikes to the level that would result in extraordinary costs. As such, the MERC-Consolidated PGA area did not incur any extraordinary costs.

V. MERC-NNG NATURAL GAS SUPPLY SOURCING

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide an overview of how MERC obtains firm natural gas service for the MERC-NNG PGA area.

Q. PLEASE PROVIDE AN OVERVIEW OF MERC FIRM PIPELINE CAPACITY RIGHTS TO MEET DESIGN DAY REQUIREMENTS WITHIN THE MERC-NNG PGA AREA.

A 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.

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

Q. PLEASE DESCRIBE THE CAPACITY RELEASE AGREEMENT AND AMA THAT WERE IN PLACE DURING THE FEBRUARY EVENT WITH RESPECT TO MERC-NNG'S PIPELINE CAPACITY ON NORTHERN BORDER.

A Recognizing that its upstream Northern Border capacity was not needed every day, in order to mitigate daily capacity reservation fees and reduce associated gas costs, MERC-NNG entered into an AMA with a counterparty AMA Counterpartyrelated to its Northern Border capacity. Under the terms of the AMA, the AMA Counterparty paid an annual fee to MERC in return for the rights to 40,000 Dth/day of MERC's firm transportation capacity on Northern Border. In addition, to ensure that peak day requirements remained supported by this upstream capacity, MERC and the AMA Counterparty entered into a daily call

option agreement under which the AMA Counterparty agreed to provide 40,000 Dth/day of supply to MERC at Ventura when called upon by MERC.

Although the portion of its Northern Border capacity subject to the AMA included favorable terms for MERC, in order to maintain geographic supply diversity in the portfolio, MERC-NNG retained the remaining 10,000 Dth/day of firm transportation capacity on Northern Border for its own use.

Q. PLEASE PROVIDE A SUMMARY OF PHYSICAL RECEIPT POINT LOCATIONS INTO NORTHERN AVAILABLE TO MERC DURING THE FEBRUARY EVENT IN SUPPORT OF ITS MERC-NNG PGA AREA.

A. During the 2020-2021 winter season, 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. Exhibit ___ (TCS-D), Schedule 4 is a map showing the location of these receipt points.

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**

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

VI. MERC-NNG GEOGRAPHIC DIVERSITY OF SUPPLY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide a summary of the various natural gas supply sources that were available to MERC within its portfolio of services in the MERC-NNG PGA area, and how these services were utilized to meet system demand and review the reasonableness of MERC supply sourcing decisions before and during the February Event.

Q. BASED UPON YOUR EXPERIENCE AND IN YOUR PROFESSIONAL OPINION, DID MERC APPROPRIATELY UTILIZE THE GEOGRAPHIC DIVERSITY IN ITS PORTFOLIO TO MINIMIZE EXPOSURE TO RISING DAILY GAS PRICES DURING THE FEBRUARY EVENT?

A. Yes. During the February Event, based on the physical location of MERC-NNG's PGA area markets and its portfolio of firm pipeline services, the only sources available to obtain required incremental daily natural gas supply during the February Event were at Northern-Ventura and to a much smaller degree at Northern-Demarc. MERC had no alternative supply locations available during the February Event to meet daily requirements in the MERC-NNG PGA area.

As MERC-NNG PGA area markets all receive natural gas via Northern, during the February Event, supply options were limited to those sourced via MERC-NNG's firm receipt point MDQs listed in Table 1. Other than receipts into

Northern via Great Lakes, all MERC-NNG firm receipt point capacity into Northern is at locations where gas that is purchased and sold is priced based upon the Northern-Demarc or Northern-Ventura gas price indices. Further, as the Great Lakes/Northern interconnects are not liquid[2] supply points, there is no liquid natural gas market at these points to provide a reliable source of natural gas on a daily basis. As a result, since no liquid daily market exists at these locations, in order to ensure natural gas supplies are available under design day conditions, natural gas supplies must be purchased at these locations on a term or first of month ("FOM") basis. If MERC-NNG were to rely upon the availability of supplies at these locations on a spot daily basis, the lack of market liquidity would result in a risk that natural gas may simply not be available when needed.

With natural gas demand and prices rising during the February Event, MERC's 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. As MERC utilized the only locations in its portfolio that were available to source supplies during the February Event, MERC

[2] A "Liquid" market is a market made up of many buyers and sellers at which a large volume of transactions occur and at which it is easy to buy and sell an asset (natural gas in this case) at fair or current market value.

Cambridge Dictionary defines a "liquid market" as a financial market in which it is easy to buy and sell, and in which a lot of buying and selling take place.
https://dictionary.cambridge.org/us/dictionary/english/liquid-market

appropriately utilized the the geographic diversity in its portfolio during the February Event.

Q. PLEASE DESCRIBE NATURAL GAS SUPPLY LIQUIDITY AND AVAILABILITY AT MERC-NNG'S SUPPLY RECEIPT POINTS FROM NORTHERN BORDER AND/OR AT DEMARC INTO NORTHERN.

A. The connection between Northern and Northern Border at Ventura is a large capacity (≈ 2.4 billion cubic feet per day ("Bcfd")) pipeline interconnect. Likewise, the Northern-Demarc location, which represents the demarcation between Northern's field and market areas is also a significant supply source on the Northern system with a throughput capacity to points north of Demarc of about 2.0 Bcfd. As large volume receipt locations, 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-NNG's supply portfolio as the liquidity at these locations provides MERC with a greater level of certainty that natural gas supplies can be purchased on the daily market to meet system demand requirements during cold and/or peak design day conditions.

Q. PLEASE DESCRIBE NATURAL GAS SUPPLY LIQUIDITY AND AVAILABILITY AT THE GREAT LAKES – GRAND RAPIDS RECEIPT POINT LOCATION.

A. Per Northern's Electronic Bulletin Board ("EBB"), Northern's interconnect with Great Lakes at Grand Rapids, Minnesota has a total design receipt capacity of only 24,000 Dth/day. As this is a small receipt point location, there is no real daily market for natural gas purchase and sale transactions at the Grand Rapids receipt point into Northern. As a result, 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.

Q. DID MERC UTILIZE THE GREAT LAKES-GRAND RAPIDS INTERCONNECT DURING THE FEBRUARY EVENT?

A. Yes, MERC purchased baseload supply for the 2020-2021 winter season at the Great Lakes Grand Rapids interconnect into Northern. This baseload supply was used by MERC during the February Event to meet system demand requirements. As this point was utilized for baseload supply and, as described above does not provide a liquid daily market for daily purchases, this receipt point did not support daily purchasing during the February Event.

Q. PLEASE DESCRIBE NATURAL GAS SUPPLY LIQUIDITY AND AVAILABILITY AT THE GREAT LAKES – CARLTON RECEIPT POINT LOCATION.

A. The Great Lakes interconnect with Northern at Carlton has a unique status on Northern's system. As designed, in order to support design day operations and enable Northern to meet firm market demand requirements, it must receive a base quantity of supply at the northernmost points on its pipeline system. To ensure that this requirement is met, Northern has a tariff right to impose an obligation on a specific set of shippers, defined as "Sourcers" in Northern's FERC Gas Tariff, Sixth Revised Volume No. 1 ("FERC Gas Tariff"),[3] such as MERC, that when called upon by Northern they must receive a predefined quantity of gas at Carlton or other similar points agreed to by Northern. In Northern's FERC Gas Tariff, this tariff obligation imposed on Northern's Sourcers is defined as the "Carlton Obligation." During the winter, when Northern calls upon the Carlton Obligation, Sourcers must receive their Carlton Obligation quantity into the Northern system at Carlton or be subject to penalties and potential capacity curtailments.

Thus, maintaining receipts at Carlton is critical for shippers on Northern who are subject to the Carlton Obligation such as MERC, not only to meet cold weather customer demand requirements but also to comply with Northern's FERC Gas Tariff and avoid imposition of penalties and potential curtailments.

[3] Northern's FERC Gas Tariff, Sixth Revised Volume No. 1, First Revised Sheet Number 263.

Although the interconnect capacity at Carlton is fairly large (Northern reports this interconnect as having a capacity of 489,000 Dth/day on its EBB) there are a limited number of firm transportation service capacity holders on the Great Lakes system with firm transportation capacity available to sell gas into Northern at this location. Faced with a tariff obligation to receive supplies at Carlton during the winter and a limited number of suppliers able to provide gas at this location, shippers typically make term baseload FOM supply arrangements at Carlton and do not take a risk that supplies will be unavailable at Carlton when Northern calls a Carlton Obligation. With minimal activity at this location with few sellers and most buyers acquiring gas on a term basis, there is minimal daily transactional activity at Carlton resulting in a lack of daily liquidity of supply at Carlton during the winter.

Q. DID MERC PURCHASE NATURAL GAS AT CARLTON TO MEET SYSTEM REQUIREMENTS DURING THE FEBRUARY EVENT?

A. As there is no liquid market for daily supply transactions at Carlton, MERC purchased supplies at Carlton on a FOM baseload basis to meet system requirements during the 2020-2021 winter. This baseload supply from Carlton was utilized to meet MERC-NNG PGA area demand requirements during the February Event.

Q. YOU MENTIONED EARLIER THAT MERC HAD 10,000 DTH/DAY OF UPSTREAM CAPACITY ON NORTHERN BORDER AVAILABLE TO SOURCE SUPPLIES INTO NORTHERN. HOW IS NATURAL GAS SUPPLY INTO THE NORTHERN BORDER SYSTEM PRICED ON THE OPEN MARKET?

A. The Ventura delivery point from Northern Border to Northern is the largest point of liquidity on Northern Border. As a result, over time the market has developed such that transactions for purchase and sale of gas on Northern Border, regardless of location, are typically priced based upon a Ventura index price plus a premium (or less a discount) based upon the physical location of the gas.

Q. DURING THE FEBRUARY EVENT, DID MERC PURCHASE NATURAL GAS SUPPLY INTO THE 10,000 DTH/DAY OF NORTHERN BORDER CAPACITY THAT IT RETAINED FOR ITS OWN ACCOUNT?

A. Yes. MERC's purchase of natural gas into its upstream Northern Border capacity is a good example of the Ventura pricing mechanism.

When purchasing winter term supplies during the summer prior to the February event (summer 2020), MERC filled this capacity with baseload supply at Port of Morgan, Montana through the peak 2020-2021 winter months of December through February. This baseload firm supply agreement was priced at the Inside FERC FOM Index for Northern Ventura less a discount.

Further, the discount versus the Inside FERC FOM Ventura index was fixed through the peak three-month period at a level that more than offset the cost MERC incurred for the upstream capacity on Northern Border during these months.

Q. WHY DID MERC FILL ITS NORTHERN BORDER CAPACITY WITH BASELOAD SUPPLY?

A. The natural gas that MERC purchases into its Northern Border capacity (as illustrated in the pricing obtained this past winter of the Ventura index less a discount) is the lowest cost supply available to MERC. As the lowest cost supply, in order to minimize gas costs, during the summer of 2020, MERC arranged a term firm baseload winter natural gas purchase into its Northern Border capacity to ensure that this lowest cost natural gas supply would flow each day during the winter season.

Q. WOULD MERC HAVE AVOIDED EXPOSURE TO THE PRICE SPIKES THAT OCCURRED DURING THE FEBRUARY EVENT IF IT HAD RESERVED A PORTION OF THE NORTHERN BORDER CAPACITY TO SUPPORT DAILY PURCHASES?

A. No. As mentioned previously, natural gas purchased into Northern Border is purchased based on the Ventura index price. As such, if MERC had reserved

purchases into Northern Border as daily gas purchases, MERC would have remained exposed to the daily price index at Ventura.

Further, if MERC had reserved this capacity for daily purchase opportunities, MERC would have increased overall baseload gas costs through the loss of the baseload discount to the Ventura index each day during the winter season.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO MERC-NNG'S USE OF THE GEOGRAPHIC DIVERSITY OF SUPPLY IN ITS PORTFOLIO DURING THE FEBRUARY EVENT?

A. First, as explained above, due to a lack of market liquidity, acquisition of supplies at the interconnects between Great Lakes and Northern is not a viable daily purchasing alternative as reliance upon this illiquid market for daily supply purchases would put MERC at risk of not being able to secure supplies when needed on the coldest days of the winter.

Next, purchases into MERC's reserved capacity on Northern Border was properly utilized for baseload purchases to minimize overall gas costs. Further, even if this location had been reserved for daily purchases, MERC-NNG customers would have remained exposed to Ventura pricing.

Finally, all other MERC-NNG firm receipt points into Northern are priced at Demarc and Ventura gas price indices. As such, in order to ensure supplies for its MERC-NNG PGA area customers, MERC had no choice other than to purchase supplies at locations that are typically priced at Ventura and/or Demarc indices.

Q. YOU MENTIONED PREVIOUSLY THAT MERC-CONSOLIDATED HAD CAPACITY ON THE VIKING SYSTEM. COULD MERC-NNG HAVE SOURCED NATURAL GAS THROUGH THE MERC-CONSOLIDATED CAPACITY ON VIKING INTO THE NORTHERN SYSTEM TO SERVE MERC-NNG PGA AREA MARKETS DURING THE FEBRUARY EVENT?

A. No. Ignoring any regulatory concerns that might arise with using MERC-Consolidated capacity to serve MERC-NNG customers, there are several reasons why this was not a viable supply alternative for MERC-NNG PGA area markets.

First, MERC-NNG PGA area markets are all served via direct deliveries from the Northern system and cannot be served directly via Viking. To serve MERC-NNG markets via Viking, the natural gas would need to flow from Viking into Northern and subsequently through Northern to the MERC-NNG delivery point locations. However, MERC-NNG does not have any firm transportation capacity on the Viking system, nor does it have any primary receipt point capacity rights into its

firm transportation capacity on Northern from any of Northern's interconnects with Viking.

Since MERC has no firm capacity on Viking and does not have primary receipt point rights from Viking into its transportation service capacity on Northern, if MERC-NNG had attempted to use a transportation path from Emerson through Viking and into its Northern capacity during the February Event, MERC-NNG would have had to use interruptible and/or secondary capacity receipt point rights to transport this gas to its service area. The use of secondary or interruptible capacity would have exposed MERC to capacity curtailments or potential cuts during this high demand period. As the February Event had high-demand days across the region, this would have put MERC-NNG at risk of its capacity being un-scheduled or curtailed during the day. As such, use of receipts at non-primary receipt points such as the Viking-Northern interconnects would not have been reasonable.

VII. MERC'S USE OF STORAGE DURING THE FEBRUARY EVENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I describe MERC's use of storage and explain how MERC optimized its use of available storage contracts to avoid additional daily gas purchases, avoid pipeline imbalance penalties, and provide service to customers through the February Event.

Q. PLEASE SUMMARIZE MERC-NNG'S AVAILABLE STORAGE CAPACITY DURING THE FEBRUARY EVENT.

A. During the 2020-2021 winter season, MERC had two Firm Deferred Delivery ("FDD") rate schedule storage agreements with Northern to meet demand requirements for MERC customers on the MERC-NNG PGA. The following 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 during the February Event.

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.

Q. DID MERC PLAN TO FULLY UTILIZE ITS MERC-NNG PGA AREA STORAGE CAPACITY DURING THE FEBRUARY EVENT?

A. Yes. 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 (nominations due no later than 1:00 p.m. the day prior to flow).

Q. WHAT PROCESS DID MERC UTILIZE TO DETERMINE HOW MUCH DAILY SUPPLY WAS REQUIRED DURING THE FEBRUARY EVENT?

A. Due to the structure of the natural gas market, in order to purchase natural gas at Gas Daily Index Prices, natural gas purchases must be made prior to 9 a.m. one day prior to the day of gas flow. During the February Event, MERC reviewed its forecast for system demand requirements one day prior to gas flow (or in the case of the four-day period of February 13–16, the day prior to February 13) when received at 7:30 a.m.[4] Next, as forecasted system demand includes demand for MERC's on-system Transportation service customers, the next step in MERC's process is to subtract the Transportation customer demand from total forecasted demand to develop forecasted system sales demand for the day.

Since nominations from MERC's Transportation customers are not required to be submitted to MERC until 9 a.m. the day prior to gas flow, MERC utilizes the Transportation customer demand during the prior twenty-four hours, plus or minus any known changes to reflect projected Transportation customer demand for the day of flow. Transportation customer demand for the prior 24-hour period

[4] TherMAXX/Marquette GasDay Forecast as of 7:30 AM on 02/12/2021.

was subtracted from the system forecast to develop a system sales demand forecast for each day during the February Event.

Next, MERC 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.

Finally, as forecasted demand will never precisely equal actual demand, in order to ensure that actual demand requirements were fully supported and to avoid any under-delivery penalties, MERC also purchased a small (< 2%) reserve supply.

The following Table 3 provides a summary of the forecasted demand and supply acquisistion processs described above.

Table 3 - Forecasted Demand and Supply (Feb. 13-Feb. 17)

Day of Gas Flow	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021
Final Date to Purchase Daily Supplies Flow Day	2/12/2021	2/12/2021	2/12/2021	2/12/2021	2/16/2021
Forecast Data					
7:30 AM Day Ahead Forecast	431,685	456,675	433,605	399,023	391,379
Final – Transport Scheduled Gas	(150,437)	(146,905)	(138,525)	(138,405)	(137,100)
Latest Transport Info Known at Time of Purchase	(187,789)	(187,789)	(187,789)	(187,789)	(138,405)
System Requirements (Forecast less Transport)	243,896	268,886	245,816	211,234	252,974
Storage WD - Start of Day Storage Nominations	87,341	87,341	87,341	87,341	87,341
Delivered Storage per Start of Day Nominations	86,302	86,302	86,302	86,302	86,302
Planned Delivered (supply less Northern fuel)					
Term Baseload	94,640	94,640	94,640	94,640	94,640
Physical Forward Option	38,779	38,779	38,779	38,779	38,779
Spot Purchase	56,832	56,832	56,832	56,832	29,644
Planned Supply - Long/(Short) vs Forecast	32,657	7,667	30,737	65,319	(3,609)
Reserve Delivered Supply (%)	7.56%	1.68%	7.09%	16.37%	-0.92%

Q. PLEASE DESCRIBE THE UNIQUE GAS PURCHASING ENVIRONMENT THAT EXISTED DURING THE FEBRUARY EVENT DURING THE FOUR-DAY PERIOD OF FEBRUARY 13 THROUGH FEBRUARY 16.

A. Natural gas commodity markets are not active during weekends and holidays. As a result, during a typical week, daily natural gas purchases for Saturday, Sunday and Monday are made on Friday morning and must be made ratably (at

the same quantity each day) over this period. In other words, the same volumes need to be purchased for each gas day within the period.

Since, Monday, February 15 was a holiday (President's Day), this weekend purchasing issue was further amplified. Specifically, with natural gas commodity markets closed on the holiday, the typical three-day purchasing window was extended to a four-day purchasing window. As a result, MERC had to complete daily gas purchases on Friday, February 12 for the four-day period February 13 through February 16.

Natural gas purchased for the four-day period of February 13 through February 16 needed to be made no later than Friday, February 12 and also had to be made ratably over the four-day weekend.

Q. ONCE NATURAL GAS SUPPLY HAS BEEN PURCHASED FOR A DAY, DOES MERC HAVE THE RIGHT TO REDUCE ITS PURCHASE QUANTITY DURING THE DAY OF GAS FLOW?

A. No. The structure of the gas market does not typically allow for changes to purchased gas supply quantities during the day. Once a natural gas supply transaction is agreed upon, the purchase and sales quantity are in effect for the entire day of gas flow or on multiple days in the case of a weekend or holiday such as the four day period during the February Event.

Q. HOW DID THE REQUIREMENT THAT NATURAL GAS PURCHASES NEEDED TO BE MADE RATABLY OVER THE FEBRUARY 13–16 FOUR-DAY PERIOD IMPACT MERC'S ACTIONS DURING THE FEBRUARY EVENT?

A. When planning for the February 13–16 period, with no ability to change flowing purchased supply quantities, MERC had no choice but to plan its daily gas supply purchases based upon the highest forecasted demand day over the period.

Table 3 above and Exhibit___ (TCS-D), Schedule 2 provide an illustration of MERC's forecasted natural gas demand and actual natural gas purchases. As illustrated in Row 3 of Exhibit ___ (TCS-D), Schedule 2, as of 7:30 a.m. on Friday, February 12, the highest forecasted demand over the four-day period was for February 14 at 456,675 Dth/day. As illustrated in Table 3, following the procedures described above, this led to a planned daily gas purchase requirement of 56,832 Dth/day for Sunday, February 14, which, per the market structure, was taken ratably by MERC over the four-day period.

Q. WHAT EXPOSURE DID MERC HAVE IF ITS NOMINATED GAS SUPPLY WAS NOT SUFFICIENT TO MEET DEMAND REQUIREMENTS DURING THE FEBRUARY EVENT?

A. During the February Event, Northern had called a system overrun limitation ("SOL") for each day of the event with 0% System Management Service ("SMS") available and had also issued a Critical Day notice during each day of the event.

The impact of the Critical Day notice and SOL was that all delivery tolerance above the scheduled quantity was eliminated and that all shippers on the Northern system, such as MERC-NNG, were subject to significant penalties if out of balance. Based upon Northern's FERC Gas Tariff, these penalties can be as high as three times the highest published Platt's Gas Daily Midpoint index price at Northern Demarc or Northern Ventura. Ultimately, per Northern's FERC Gas Tariff provisions[5], Northern calculated the penalty amount per tariff provisions as $695.01/Dth during the February Event of over-delivery versus scheduled quantities.

Q. PLEASE DESCRIBE THE PROCESS USED BY MERC TO BALANCE SUPPLIES WITH ACTUAL SYSTEM DEMAND REQUIREMENTS DURING EACH DAY OF GAS FLOW DURING THE FEBRUARY EVENT.

A As 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. Rather, MERC's only

[5] FERC Gas Tariff, Sixth Revised Volume No. 1, First Revised Original Sheet No. 291 and Fourth Revised Sheet No. 291A available at https://apps.northernnaturalgas.com/Public/Tariff/Data/EntireTariff.pdf.

option to balance supplies with actual deliveries each day was to adjust storage withdrawals during the day.

As MERC is an FDD storage service capacity customer, 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 a.m. immediately prior to the 23rd hour of the Gas Day.[6] This 23rd hour storage nomination enables MERC to reduce its daily withdrawal quantity to the extent necessary to balance supplies with demand requirements.

As illustrated in Exhibit ___ (TCS-D), Schedule 2 Rows 14-25, based upon a review of demand requirements as of the 23rd hour of flow and available flowing, MERC reduced storage withdrawal quantities via the 23rd hour storage nomination each day during the February Event.

Q. ULTIMATELY, DID MERC'S SUPPLY ACQUISITIONS BALANCE WITH DEMAND REQUIREMENTS?

A. Yes. As illustrated in the calculations in Rows 26 through 36 of Exhibit ___ (TCS-D), Schedule 2, after the 23rd hour storage nomination changes and based upon actual deliveries, MERC gas supply deliveries were greater than actual

[6] Gas Day is defined in Northern's FERC Gas Tariff as "a period of twenty-four (24) consecutive hours, beginning and ending at 9:00 a.m. central clock time." FERC Gas Tariff, Sixth Revised Volume No. 1, Third Revised Sheet No. 204, available at https://apps.northernnaturalgas.com/Public/Tariff/Data/EntireTariff.pdf.

demand requirements but within the allowable 5% tolerance per MERC's firm capacity rights on Northern.

Q. DID MERC MAXIMIZE ITS USE OF STORAGE CAPACITY DURING THE FEBRUARY EVENT?

A. Yes, it did. Within its initial storage nomionation based upon forecasted demand requirements, MERC-NNG nominated 100% of its available storage withdrawal capacity to meet demand requirements. Subsequently, as the 23rd hour storage nomination process was the only tool available to MERC to balance supplies with system demand requirements, storage nominations were lowered for balancing purposes. This said, based upon the information that MERC-NNG had available at the time that gas supply purchases were made, storage nominations were at maximum levels and as a result, MERC maximized the use of its storage capacity during the February Event.

VIII. MERC'S USE OF DAILY INDEX PRICED VS FIXED-PRICE NATURAL GAS SUPPLY DURING THE FEBRUARY EVENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss how MERC's gas procurement plan prudently utilized daily index pricing versus fixed-price gas supplies during the February Event.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MARKET FOR NATURAL GAS COMMODITY TRANSACTIONS AT VENTURA AND DEMARC.

A. As mentioned previously, both Ventura and Demarc are large volume trading points with significant purchase and sale transactions made by a large number of buyers and sellers. As large liquid markets with trading information available on ICE[7] as well as in over-the-counter markets, Ventura and Demarc are efficient markets with market information generally available to all market participants at any given time.

As such, it is unreasonable to think that a single participant can predict market dynamics and enter into fixed-price transactions that "beat the market" at any given time.

Given these circumstances, attempts to "beat the market" by purchasing natural gas at a specific time or at a specific traded price are speculative.

Q. PLEASE SUMMARIZE MERC-NNG DAILY PRICED PURCHASES DURING THE FEBRUARY EVENT.

A. First, 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.

[7] Per the ICE website: *"ICE was established in 2000 on the principles of price transparency and market efficiency. We led the industry in standardizing over-the-counter (OTC) energy contracts and listing them on a widely distributed electronic trading platform. Today, our transparent OTC energy market provides physically settled bilateral contracts for global crude and North American natural gas and power to satisfy the hedging and trading objectives of a diverse range of market participants." ICE OTC Energy*, https://www.theice.com/otc-energy.

Next, MERC-NNG made daily purchases of 54,641 Dth/day at Ventura and 2,376 Dth/day at Demarc for the period of February 13-16, on a ratable basis, as described above.

Finally, on February 17 MERC-NNG purchased 30,000 Dth/day of daily purchases at Ventura.

Q. WHAT PRICING MECHANISM APPLIED TO THESE DAILY GAS PURCHASES MADE BY MERC?

A. Each of the aforementioned daily gas purchases was made based upon the price published as the Midpoint price by Platts Gas Daily within the Final Daily Price Survey for the relevant Flow Date and Location (i.e., Ventura or Demarc). I will refer to these prices herein as the "Gas Daily Index Price"

Q. HOW DOES PLATTS DEVELOP THE GAS DAILY INDEX PRICE FOR A LOCATION AND FLOW DATE?

A. Per its 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."

To sum up, 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.

Q. IS IT STANDARD INDUSTRY PRACTICE TO PURCHASE NATURAL GAS AT INDEX-BASED PRICES?

A. Yes. In fact, the vast majority of natural gas purchased and sold in US markets is done so 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 this presentation, FERC staff observed that in 2019, 82% of the traded volume of natural gas transactions referenced natural gas indices.[8] The fact that 82% of traded volumes referenced index price mechanisms, is clear indication that this is the industry standard.

Subsequent to this presentation, FERC posted the transactional information collected through the Form 552 process for calendar year 2020.[9] Per this

[8] https://cms.ferc.gov/news-events/news/staff-presentation-price-index-policy-statement-and-safe-harbor-price-index-nopr

[9] *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-and-safe-harbor-price-index-nopr.

posted data, approximately 83% of natural gas purchases reported in the FERC Form 552 for 2020 referenced index price mechanisms. Further, these purchases were split roughly evenly with about 40% referencing "Next Day Delivery Gas Price Indices" and about 43% referencing "Next Month Delivery Gas Price Indices." Once again, this is clear indication that the use of Next Day or Daily gas price indices is standard industry practice with respect to natural gas purchasing.

This said, the US natural gas market is a large liquid market. As such, the remaining 17% of natural gas purchases in 2020 that do not reference index price mechanisms and which are used to set the price for the index represent a significant quantity of traded gas[10].

Q. WAS IT REASONABLE FOR MERC-NNG TO PURCHASE ITS DAILY NATURAL GAS SUPPLIES BASED UPON THE GAS DAILY INDEX PRICE AS OPPOSED TO PURCHASING AT FIXED DAILY PRICES?

A. Yes. As daily natural gas price markets can be volatile, the 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

[10] Per the FERC 552 Data, this 17% of natural gas purchases represented in excess of 14,000 Trillion Btu in 2020.

average market conditions. As a result, purchasing daily gas at daily index prices is a reasonable and prudent decision.

The Gas Daily Index price versus potential fixed prices that occurred during the February Event are a good example of this risk. A review of the Absolute pricing data from Gas Daily[11] with delivery at Demarc and Ventura reveals that (i) at Ventura, (a) for the four day period of February 13-16 fixed-price physical transactions ranged from a low of $45/Dth to a high of $325/Dth versus the settled Gas Daily Midpoint index price (at which MERC purchased its daily supplies) at $154.91/Dth, and (b) for February 17 gas flows, fixed-price physical transactions ranged from a low of $80/Dth to a high of $495/Dth versus the settled Gas Daily Midpoint index price (at which MERC purchased its daily supplies) at $188.32/Dth; and (ii) at Demarc, (a) for the four-day period of February 13-16, fixed-price physical transactions ranged from a low of $80/Dth to a high of $400/Dth versus the settled Gas Daily Midpoint index price (at which MERC purchased its daily supplies) at $231.67/Dth, and (b) for February 17 gas flows, fixed-price physical transactions ranged from a low of $85/Dth to a high of $250/Dth versus the settled Gas Daily Midpoint index price (at which MERC purchased its daily supplies) at $133.635/Dth.

[11] Gas Daily Final Daily Price Survey table under the heading “Upper Midwest” at Locations Northern, Demarc and Northern, Ventura under the column “Absolute” for Flow date(s) Feb 13 – Feb 15 as published in Gas Daily dated February 16, 2021

As a result, if MERC-NNG had sought to acquire natural gas at fixed prices, the company and its customers would have potentially been at risk for prices as high as $325/Dth at Ventura and $400/Dth at Demarc during this four-day period. As mentioned above, the Gas Daily Index price represents a weighted average price of transactions for each day of gas flow. As a result, while 50% of the natural gas sold at any location might be sold at more favorable pricing using fixed prices, the remaining 50% of natural gas sold at the same location will be sold at higher prices than the index.

As prices will change during a day for a myriad of reasons, entering into fixed price transactions for daily purchases in an attempt to obtain a better price than the average market price would be speculative and would expose MERC and its customers to higher price volatility and risk.

As such, it was reasonable and prudent for MERC to purchase the necessary daily gas supplies at Gas Daily Index prices.

Q. BASED UPON THE INFORMATION KNOWN AT THE TIME, IN YOUR OPINION, WOULD IT HAVE BEEN REASONABLE FOR MERC TO PURCHASE ITS DAILY SUPPLIES AT FIXED DAILY PRICES?

A. No. Attempting to “beat the market” through the purchase of fixed price would have been speculative. Following this approach would have put MERC’s

customers at risk versus purchasing gas supplies at average market conditions, represented by the Gas Daily Midpoint Index Price.

As to the market dynamics at the time, Gas Daily reported that the range of prices for physical fixed-price transactions for gas flow on the January 13 to January 16 flow dates was between $45/Dth and $325/Dth at Ventura and between $80/Dth and $400/Dth at Demarc. Similarly, Gas Daily reported that the range of prices for physical fixed price transactions for gas flow on the January 17 flow date was between $80/Dth and $495/Dth at Ventura and between $85/Dth and $250/Dth at Demarc. In contrast, a review of historic Gas Daily settlement prices at these locations reveals that the Demarc Midpoint index price had never settled as high as the lowest absolute price transaction reported for the this period at Demarc, and only once in its history had the Ventura Midpoint index price settled at a price that was higher than the lowest absolute price transaction at Ventura reported for the period.[12] To illustrate this point, the following Table 4 provides a history of the highest daily Gas Daily Midpoint Index settlement prices for each of the past twenty years. As illustrated in Table 4 below, pricing during the February Event was unprecedented versus historic norms.

[12] Previous high for the Gas Daily Midpoint index price at Ventura was for flow date December 28, 2017 and settled at a price of $67.455/Dth on this date.

Table 4 – Historic High Gas Daily Midpoint Index Prices				
	DEMARC		Ventura	
Year	Flow Date of High Midpoint Index Price	Highest Reported Midpoint Index Price	Flow Date of High Midpoint Index Price	Highest Reported Midpoint Index Price
2002	12/20/2002	$4.820	12/20/2002	$4.820
2003	2/26/2003	$18.955	2/26/2003	$17.735
2004	10/28/2004	$7.470	10/28/2004	$7.440
2005	12/14/2005	$13.740	12/8/2005	$14.550
2006	1/4/2006	$8.400	1/8/1900	$8.530
2007	2/3/2007	$8.765	2/3/2007	$10.570
2008	6/25/2008	$11.970	6/25/2008	$12.060
2009	12/29/2009	$6.165	1/15/2009	$6.315
2010	1/8/2010	$7.590	1/8/2010	$7.590
2011	2/3/2011	$5.680	2/3/2011	$5.265
2012	11/27/2012	$4.050	11/27/2012	$4.040
2013	12/10/2013	$5.470	12/10/2013	$5.575
2014	2/5/2014	$34.950	1/27/2014	$53.305
2015	2/18/2015	$9.790	2/18/2015	$11.340
2016	12/16/2016	$4.065	12/16/2016	$4.065
2017	12/29/2017	$4.480	12/28/2017	$67.455
2018	1/2/2018	$8.385	1/2/2018	$8.560
2019	3/2/2019	$8.475	3/2/2019	$8.955
2020	10/27/2020	$4.830	10/27/2020	$6.390
2021	2/13/2021	$231.670	2/17/2021	$188.320

Even if MERC had timed purchases perfectly and had been offered supplies in the volumes needed at the low end of the absolute range of prices for physical transactions for the day, based upon the information available at the time, it is unreasonable to think that it would have been a reasonable and prudent decision for MERC to deviate from standard practice and enter into a speculative purchase transaction based upon this then-record price.

IX. ALBERTA WEATHER DATA PRIOR TO THE FEBRUARY EVENT

Q. WERE ACTUAL WEATHER CONDITIONS IN CALGARY, ALBERTA THE WEEK PRIOR TO THE FEBRUARY EVENT EXTRAORDINARY VERSUS OTHER RECENT WINTER SEASON COLD WEATHER EVENTS?

A. No. A comparison of weather conditions in Calgary, Alberta during the week leading up to the February Event indicates that low temperatures in Alberta were consistent with low temperatures seen each of the past few winters.

Table 5 provides a comparison of temperatures during the coldest 10 consecutive day period in Calgary, Alberta this past February compared to temperatures of the coldest 10 consecutive days in Calgary during the previous two years. As illustrated in the table, temperatures experienced in Calgary prior to the February Event were not inconsistent with cold weather events during the previous two years.

Table 5 – Low Temperature Events in Calgary Alberta (2018/19 – 2020/21)

2020-21		2019-20		2018-19	
Date	Temp (°F)	Date	Temp (°F)	Date	Temp (°F)
7-Feb	(23)	10-Jan	(5)	3-Feb	(18)
8-Feb	(25)	11-Jan	(5)	4-Feb	(18)
9-Feb	(25)	12-Jan	(14)	5-Feb	(21)
10-Feb	(26)	13-Jan	(25)	6-Feb	(16)
11-Feb	(28)	14-Jan	(27)	7-Feb	(15)
12-Feb	(22)	15-Jan	(28)	8-Feb	(11)
13-Feb	(17)	16-Jan	(22)	9-Feb	(19)
14-Feb	(19)	17-Jan	(18)	10-Feb	(22)
15-Feb	(14)	18-Jan	(19)	11-Feb	(19)

16-Feb	(11)	19-Jan	(7)	12-Feb	(23)
Min	**(28)**	**Min**	**(28)**	**Min**	**(23)**

As illustrated in the table, temperatures in Calgary have dropped to similar levels in each of the past three winters.

Q. LOOKING AT THE ACTUAL TEMPERATURE DATA IN ALBERTA OVER THE PAST THREE YEARS, ARE COLD ALBERTA TEMPERATURES A CLEAR SIGNAL THAT NATURAL GAS PRICES IN THE US MIDWEST WILL RISE WITHIN THE NEXT WEEK?

A. No. A review of the other cold weather events that occurred in Alberta over the past three years reveals that cold weather in Alberta does not necessarily lead to price spikes in US Midwest markets. Attached as Exhibit ___ (TCS-D), Schedule 3are graphical comparisons of Alberta temperatures versus daily natural gas prices at the US Midwest market point locations of Demarc and Ventura. As illustrated in this exhibit, extreme cold weather in Alberta had little to no effect on Midwest prices during the previous two winters of 2018-2019 or 2019-2020. Based upon this weather history, it would be unreasonable to assume that cold weather in Alberta will always lead to spikes in US Midwest gas prices.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR OVERALL OPINIONS IN YOUR TESTIMONY.

A. Based upon my review of MERC's actions and decisions before and during the February Event, I conclude that MERC's actions and decisions related to natural gas supplies were appropriate. During this critical time, with natural gas supplies limited, pipeline services restricted and natural gas demand elevated, MERC was successful in maintaining sufficient natural gas supply to meet its customer requirements. Further, MERC also made prudent and reasonable decisions regarding the use of its available portfolio of services and supplies to minimize gas costs during the event.

Specifically,

1. MERC appropriately utilized the geographic diversity of supply available in its portfolio of services during the February Event.
2. MERC appropriately utilized its storage assets during the February Event.
3. MERC's use of daily index price gas during the February Event was reasonable and consistent with industry standards.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

TIMOTHY C. SEXTON

EMPLOYMENT HISTORY

Gas Supply Consulting, Inc.
19500 SH 249, Suite 245; Houston, TX, 77070

June 1994 - Present
Current Position: President

Selected Recent Experience at Gas Supply Consulting, Inc.

- Infrastructure Development / Commercial Analysis:
  - LNG Development Company: Currently engaged by LNG liquefaction plant developers to assist in review of gas supply and gas transportation service alternatives to facility in South Louisiana.
  - US Midwest Utility Holding Company: GSC has served as consultant to a Utility Holding Company with operations throughout the US Midwest region since 1991. GSC role with this client is to provide advisory services and support in evaluation of commercial / operational and physical asset opportunities on behalf of the company and its subsidiaries.
  - Osaka Gas: GSC has served as the primary consultant to Osaka Gas Resources America (Osaka Gas) to facilitate development of pipeline infrastructure to the Freeport LNG facility. Directed process to solicit proposals and negotiate with various bidders that resulted in the construction of an approximate 70 mile (1.4 Bcf/d capacity) large diameter (36") natural gas pipeline. Supported Osaka Gas in negotiations with potential bidders, review of proposals, market evaluations, selection of winning bidder and contract negotiation.
  - FP&L – Sabal Trail and FSC Projects: Primary consultant to Florida Power & Light Company (FPL) with respect to incremental pipeline infrastructure needs to Florida markets. Provided support and assistance in developing pipeline capacity RFP, bid review including analysis of delivered cost of gas to FPL Markets, contract negotiation with winning bidder and expert witness in public service commission approval process. Negotiations led to development of Sabal Trail Pipeline and Florida Southeast Connection pipeline projects.
  - Florida Based Electric Utility: Consultant to large electric service utility in Florida market. Provide advisory services related to development of fuel portfolio including development of natural gas supply agreements, transportation service agreements, storage agreements, etc.
- Commercial Due Diligence and Support in M&A Activities: Teamed up with European Based International Consulting firm to evaluate potential acquisitions of stakes in US pipeline businesses and LNG export terminals for various clients.
- Solicitation / Acquisition of Natural Gas Supplies and Services for End Use and Utility Clients – Actively involved in and directed natural gas supply and natural gas pipeline service capacity acquisition for utility and industrial clients. Developed gas supply RFPs, interacted with suppliers, negotiated agreement terms and negotiated contracts on behalf of clients. GSC has negotiated supply and service agreements on behalf of its clients representing hundreds of billion cubic feet of natural gas supply.

- Natural Gas Infrastructure Evaluations –
  - FRCC: GSC has supported the Florida Reliability Coordinating Council (FRCC) for more than twenty years with the FRCC's ongoing evaluations of the reliability of the fuel deliverability infrastructure serving FRCC electric generation member companies.
  - CPUC: Currently engaged (along with a partner consulting company) to support the California Public Service Commission in its Phase III evaluation of alternatives or mitigations to the use of the Aliso Canyon storage facility to potentially enable retirement of the facility.
- Consulting for End User Clients – Work with clients assessing natural gas use and requirements, prepare corporate gas supply purchasing plan outlining recommended corporate purchasing strategy. Structure recommended transactions regarding supply, service and price risk management programs. Implement purchasing program on behalf of clients through negotiation of transactions with various suppliers, utilities and service providers.
- Expert Witness Services – Served as expert witness and provided oral and written testimony on behalf of several clients in various FERC and state public service commission proceedings.
- Consulting for Other Portions of the Energy Industry - Performed consulting services for a broad spectrum of clients, both domestically and internationally, including gas marketing companies, natural gas producers, transportation and storage service providers, and customer groups.

United Gas Pipeline Company (currently Gulf South Pipeline Company)

June 1989 - June 1994

Filled various positions of increasing responsibility within the operations, engineering, planning and marketing departments of Koch Gateway Pipeline Company, and its predecessor United Gas Pipeline Company, over this period

Position: Regional Manager (Supply Services)
Engineer (System Planning Department)
Associate Engineer (Engineering Department)
Staff Engineer (Operations Department)

EDUCATION

University of Houston, Houston, Texas
Master of Business Administration (Concentration in Finance), July 1993
University of Texas, Austin, Texas
Bachelor of Science Degree in Civil Engineering May 1989

OTHER

Licensed as a Professional Engineer in the State of Texas

Federal Energy Regulatory Commission Testimony

#RP21-552: **(Written Testimony)**

Submitted Direct Testimony and Answering Testimony on behalf of **Antero Resources Corporation** in FERC proceeding relating to the appropriate allocation of fuel and electric power costs between general and incremental system shippers by Tennessee Gas Pipeline Company, L.L.C. ("Tennessee").

#RP20-1220: **(Written Testimony)**

Submitted Declarations on behalf of ***Rockies Express Pipeline LLC*** in FERC proceeding to support a Finding that three negotiated rate pipeline transportation contracts between Rockies Express and Gulfport Energy Corporation remain in the Public Interest.

#RP19-1353**: (Written Testimony)**

Provided expert testimony on behalf of ***Upper Midwest Shipper Group*** in FERC proceeding concerning operational issues in Northern Natural Rate Case Proceeding.

#RP19-211**: (Written Testimony)**

Provided expert testimony on behalf of ***Range Resources*** in FERC proceeding concerning fuel retention percentages on the Columbia Gulf interstate pipeline system.

#RP04-249: **(Written and Oral Testimony)**

Served as expert witness on behalf of ***Florida Power & Light Company*** in proceeding concerned the impact of the introduction of LNG gas supplies on natural gas quality on the Florida Gas Transmission interstate pipeline system.

#CP13-743: ***(Oral Presentation)***

Provided presentation outlining position of ***Wisconsin Distributor Group ("WDG")*** in technical conference supporting WDG position in ANR Pipeline Company DTCA Settlement proceeding.

Wisconsin Public Service Commission Testimony

PSCW Docket # 6650-CG-233: **(Written and Oral Testimony)**

Provided Expert Witness testimony on behalf of We Energies subsidiary, Wisconsin Gas Company ("WG") related to WG's West Central Wisconsin Project.

Minnesota Public Utility Commission Testimony

MPUC Docket No. G-011/M-15-895: **(Written and Oral Testimony)**

Provided Expert Witness testimony on behalf of Minnesota Energy Resources Corporation ("MERC") in support of MERC's request to enter into a twenty-year transportation service agreement with Northern Natural Gas Company.

Florida Public Service Commission Testimony

FPSC Docket #130198-EI: **(Written Testimony)**

Served as expert witness in support of an Application of ***Florida Power & Light Company*** for authority to enter into long term natural gas transportation contracts supporting the construction of the Sabal Trail Transmission, LLC and Florida Southeast Connection pipelines in support of its electric generation facilities in Florida.

FPSC Docket #090172-EI**: (Written and Oral Testimony)**

Served as expert witness in support of Application of ***Florida Power & Light Company*** for authority to construct an intrastate natural gas pipeline for the purposes of gaining direct access to unconventional gas supplies in support of its electric generation facilities in Florida

United States Bankruptcy Court for the Southern District of Texas – Houston Division

Chapter 11 - Case No. 20-35562 (DRJ): **(Written Testimony)**

Submitted Declarations on behalf of Rockies Express Pipeline LLC in Bankruptcy court proceeding related to negotiated rate pipeline transportation contracts between Rockies Express and Gulfport Energy Corporation in support of Rockies Express position in opposition to Gulfport's request that the contracts be rejected by the Bankruptcy Court.

DISTRICT COURT OF TARRANT COUNTY, TEXAS 141ST JUDICIAL DISTRICT:

CAUSE NO. 141-308545-19 - RANGE RESOURCES – APPALACHIA, LLC (Plaintiffs), v. EAP OHIO, LLC AND CHESAPEAKE ENERGY MARKETING, LLC (Defendants). **(Written Testimony)**

Submitted Expert Report and Sur-Rebuttal Expert Report supporting Range Resources position in dispute regarding default under natural gas purchase and sales agreement.

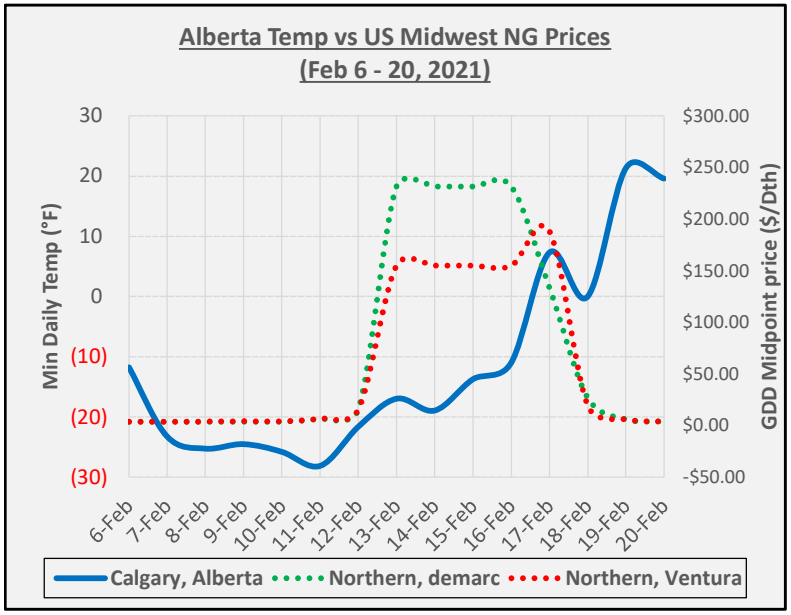
Four Day Weekend Purchases

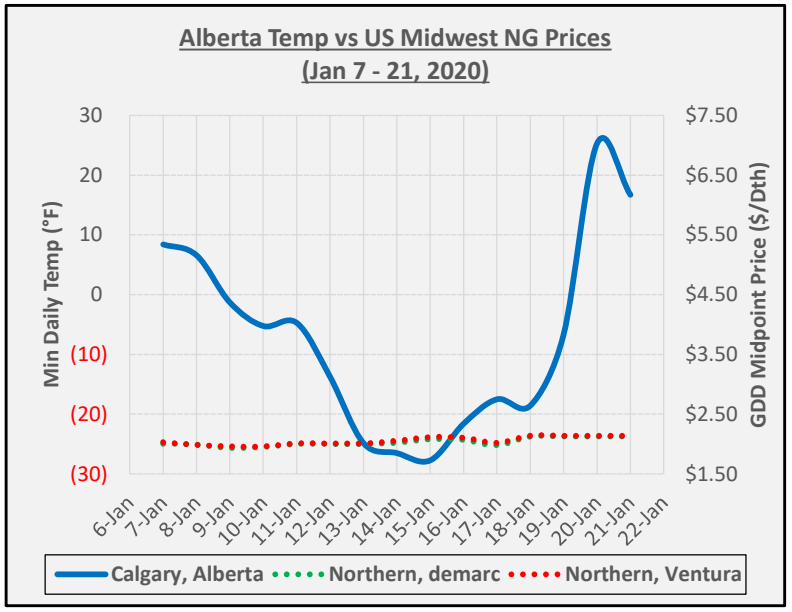
Row / Column	A	B	C	D	E	F	G
		Saturday	Sunday	Monday	Tuesday	Wednesday	
1	Day of Gas Flow	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	
2	Final Date to Purchase Daily Supplies for Date of Flow	2/12/2021	2/12/2021	2/12/2021	2/12/2021	2/16/2021	
	Gas Purchase Process Based upon Information Known at time of Final Spot Gas Purchase Day for Flow Day						
3	**7:30 AM Day Ahead Forecast for Day of Gas Deliveries**	**431,685**	**456,675**	**433,605**	**399,023**	**391,379**	
4	Final - EUT Scheduled Gas on Day of Gas Deliveries	(150,437)	(146,905)	(138,525)	(138,405)	(137,100)	
5	Latest EUT Info Known at Time of Purchase	(187,789)	(187,789)	(187,789)	(187,789)	(138,405)	
6	System Requirements (Forecast less known Transport)	243,896	268,886	245,816	211,234	252,974	
7	Start of Day Storage Nominations	87,341	87,341	87,341	87,341	87,341	
8	Delivered Storage per Start of Day Nominations	86,302	86,302	86,302	86,302	86,302	
	Planned Delivered (purchases less Northern fuel) Suppplies (Ignores Cuts)						
9	Term Baseload	94,640	94,640	94,640	94,640	94,640	
10	Physical Forward Option	38,779	38,779	38,779	38,779	38,779	**Note**: Weekend Event - due to market structure, must purchase even quantities across all four days. Purchases must satisfy coldest day plus reasonable reserve tolerance for forecast error. Planned purchases covered forecasted demand plus minimal (<2%) reserve.
11	Spot Purchase	56,832	56,832	56,832	56,832	29,644	
12	Planned Purchases/ Withdrawals - Long/(Short) vs Forecast	32,657	7,667	30,737	65,319	(3,609)	
13	Reserve Delivered Supply (%)	7.56%	1.68%	7.09%	16.37%	-0.92%	
	Storage Nomination Adjustment based upon Information Known at Time of 23rd Hr Storage Nom						
14	**23rd Hour Forecast of Gas Deliveries**	368,583	379,990	367,744	340,838	318,603	
15	23rd Hour Forecast of EUT Deliveries	(144,838)	(137,765)	(137,493)	(137,332)	(138,797)	
16	System Requirements (Actual less Transport)	223,745	242,225	230,251	203,506	179,806	
	Actual Delivered Suppplies						
17	Term Baseload	94,640	94,613	89,179	89,289	88,584	
18	Physical Forward Option	38,779	38,779	38,779	38,779	38,779	
19	Spot Purchase	56,832	56,832	54,664	56,339	29,644	
20	Required Storage Deliveries to city gate	33,494	52,001	47,629	19,099	22,799	
21	Required Storage Withdrawals (with Transport Fuel)	33,897	52,627	48,203	19,329	23,074	
22	Final Storage Nominations (at storage field)	59,341	72,846	76,545	44,846	44,846	**Note**: 23rd Hour Storage Nom is required to get supplies in balance with deliveries on Northern. SOL Days had been called by Northern for each of Feb 11 through Feb 18. Storage Withdrawals are lowered at 23rd hour nomination to balance receipts and deliveries.
23	Final Storage Nominations (at city gate)	58,635	71,979	75,634	44,312	44,312	
24	Long / (Short) for Day	25,141	19,978	28,005	25,213	21,513	
25	Imbalance Percentage vs Deliveries	6.82%	5.26%	7.62%	7.40%	6.75%	
	Final Balance based on Actuals						
	Actual Deliveries	384,481	396,883	384,569	355,829	330,575	
26	EUT Quantities	(150,437)	(146,905)	(138,525)	(138,405)	(137,100)	
27	System Requirements (Actual less Transport)	234,044	249,978	246,044	217,424	193,475	
	Actual Delivered Suppplies						
28	Term Baseload	94,640	94,613	89,179	89,289	88,584	
29	Physical Forward Option	38,779	38,779	38,779	38,779	38,779	
30	Spot Purchase	56,832	56,832	54,664	56,339	29,644	
31	Required Storage Deliveries to city gate	43,793	59,754	63,422	33,017	36,468	
32	Required Storage Withdrawals (with Transport Fuel)	44,320	60,474	64,186	33,414	36,907	
33	Final Storage Nominations (at storage field)	59,341	72,846	76,545	44,846	44,846	
34	Final Storage Nominations (at city gate)	58,635	71,979	75,634	44,312	44,312	
35	Long / (Short) for Day	14,842	12,225	12,212	11,296	7,844	**Note**: After nomination changes, actual supplies to system are within 5% tolerance of actual deliveries.
36	Imbalance Percentage vs Deliveries	3.86%	3.08%	3.18%	3.17%	2.37%	

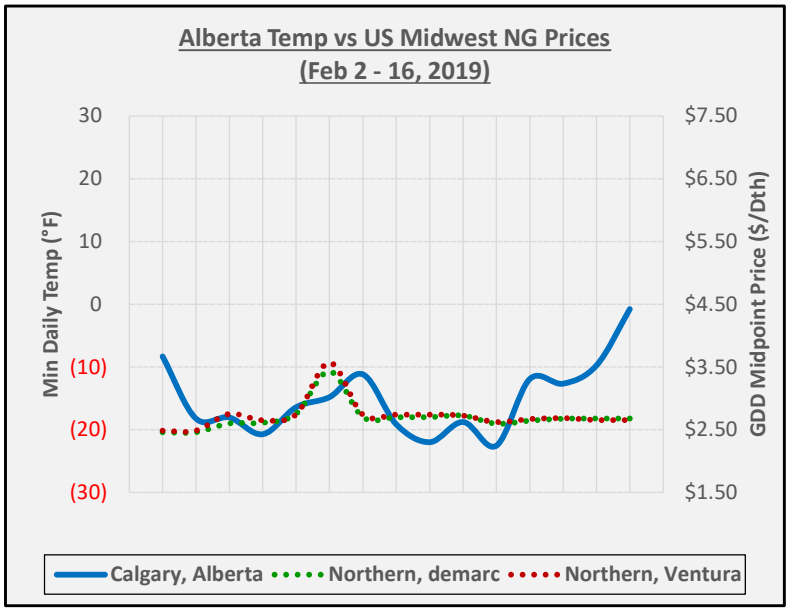
[1/] 7:30 AM Day Ahead Forecast reflects the final forecast provided by TherMAXX/Marquette to MERC prior to the finall window of gas purchasing for the day.

[2/] 23rd Hour Forecast of Gas Deliveries is equal to the quantity of gas that had been phyiscally delivered during the previous 23 hours of the day plus a projection for the final hour of the day.

Alberta Temperature (°F) on Extreme Cold Days vs US Midwest Natural Gas Prices ($/Dth)







Notes:

Historic weather data for Calgary, Alberta daily as reported by the Government of Canada for the "CALGARY INT'L CS ALBERTA" weather station in °C and converted to °F.

Daily Natural Gas Index Prices for "Northern, demarc" and "Northern, Ventura" reflect the Midpoint price as reported by PLATT's Gas Daily in its Final Daily Price Survey for the day of delivery at these locations

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