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

IN THE MATTER OF THE PETITIONS FOR RECOVERY OF CERTAIN GAS COSTS	OAH Docket No. 71-2500-37763
IN THE MATTER OF THE PETITION OF CENTERPOINT ENERGY FOR APPROVAL OF A RECOVERY PROCESS FOR COST IMPACTS DUE TO FEBRUARY EXTREME GAS MARKET CONDITIONS	MPUC Docket No. G008/M-21-138
IN THE MATTER OF THE PETITION BY GREAT PLAINS NATURAL GAS CO., A DIVISION OF MONTANA-DAKOTA UTILITIES CO., FOR APPROVAL OF RULE VARIANCES TO RECOVER HIGH NATURAL GAS COSTS FROM FEBRUARY 2021	MPUC Docket No. G004/M-21-235
IN THE MATTER OF A PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY TO RECOVER FEBRUARY 2021 NATURAL GAS COSTS	MPUC Docket No. G002/CI-21-610
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/CI-21-611

DIRECT TESTIMONY OF

RICHARD G. SMEAD
On Behalf of
JOINT GAS UTILITIES

October 22, 2021

Exhibit___(RGS-1)

**Detailed Overview of the U.S. Natural Gas Industry
and
The Extreme Weather Event of February 2021**

Table of Contents

I.	Introduction and Qualifications		1
II.	Overview of U.S. Natural Gas Markets		2
	A.	Physical Natural Gas Markets	3
	B.	Marketplace Transparency and How Prices Are Set	7
	C.	Comparison of Gas Markets with Power Markets	15
	D.	Factors Affecting Natural Gas Prices	20
	E.	Interstate Gas Pipeline Tariffs	23
	F.	Risk Management	25
III.	LDC Gas Procurement Practices		30
IV.	Winter Storm Uri and Natural Gas Market Impacts		39
	A.	Weather Forecasts and Experience	40
	B.	Loss of Supply in Texas and Oklahoma	46
	C.	Response by Market Participants, February 11-16	50
	D.	Nature of Price Behavior	53
	E.	Minnesota Vs. Texas	55
VI.	Conclusion		56

Schedules

Statement of Qualifications	Schedule 1
Prior Testimony of Richard G. Smead	Schedule 2
Map of Relevant Natural Gas Pipelines and Trading Hubs	Schedule 3
Breakdown of Commodity Deals 2020	Schedule 4
Overall and Relevant Loss of Supply	Schedule 5
Northern & NiGas Critical Notices	Schedule 6
Historical Price Behavior	Schedule 7

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard G. Smead. My business address is 2323 S. Shepherd Dr., Suite 1010, Houston, Texas 77019.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by RBN Energy LLC. My title is Managing Director, Advisory Services.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company d/b/a Xcel Energy, CenterPoint Energy Resources Corp d/b/a CenterPoint Energy Minnesota Gas, Minnesota Energy Resources Corporation and Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co. (collectively, the Joint Gas Utilities).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I hold a Bachelor of Science in Mechanical Engineering from the University of Maryland and a Juris Doctor degree from George Washington University. I have 34 years of experience in the natural gas industry, 10 years working for the local distribution system serving the Washington, D.C. metropolitan area, and 24 years working for major pipeline companies (16 of which were in senior management). I also have 17 years of experience consulting in all regulatory, commercial, and strategic aspects of the natural gas industry. In particular, for the last 13 years, I have focused on the emergence of natural gas abundance through shale development, its implications for the industry and for the world.

In 2008, I managed and presented the first comprehensive estimate of what shale gas was ultimately going to be worth, a pivotal change in the natural gas industry. At RBN, I have also been deeply involved in understanding and helping build the firm's work with the Permian Basin in Texas, an important factor in this proceeding. Our expertise involves the economics of oil and gas production, estimates of future production, the state of the infrastructure to allow natural gas to move to market, and the actual patterns of flow from the basin. A full statement of my qualifications and experience is provided as Exhibit___(RGS-1), Schedule 1, followed by a list of all my prior testimony in Exhibit___(RGS-1), Schedule 2.

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

A. To provide a background for the issues faced by the four Joint Gas Utilities during the week of Presidents Day, 2021 my testimony presents:

- A broad overview of the U.S. natural gas market,
- A detailed explanation of typical gas procurement practices by a local natural gas distribution company (LDC), and
- A detailed account of the events leading up to and during Winter Storm Uri, both generally and specifically in Minnesota.

II. OVERVIEW OF U.S. NATURAL GAS MARKETS

Q. HOW DO YOU APPROACH THE OVERVIEW OF U.S. NATURAL GAS MARKETS?

A. The overview is broken into six parts:

(1) physical markets including market participants,

(2) marketplace transparency and how prices are set,

(3) a high-level comparison to electric power markets,

(4) an explanation of the risk-management tools available, both physical and financial, to gas purchasers,

(5) a general explanation of the factors that can affect natural gas prices, and

(6) the structure of and issues presented by interstate natural gas pipeline tariffs.

A. Physical Natural Gas Markets

Q. PLEASE DESCRIBE THE STRUCTURE OF THE PHYSICAL NATURAL GAS MARKET.

A. The U.S. natural gas market consists of distinct segments with varying dynamics, varying states of regulation and deregulation, but strong interdependence. Natural gas is often viewed by parties outside the industry as being similar in structure to the electric power industry – as a single, fully-integrated system. It is not. Physically, it consists of multiple disparate entities, often operating independently.[1]

- Producers drill the wells that bring raw natural gas (a mix of methane, various other hydrocarbons such as ethane, propane and butane, plus impurities such as water or nitrogen) to the surface, frequently as a byproduct of oil production.
- Midstream gathering and processing entities carry the raw gas to treatment and processing facilities, where impurities are removed to meet pipeline specifications, and hydrocarbons other than methane are removed both to meet pipeline specifications and to be resold for their own market value.
- Transmission pipelines move dry (processed) gas and gas from storage to distant consuming markets.

[1] One aspect of the physical market not discussed is the delivery of natural gas to liquefied natural gas (LNG) terminals for export to other nations – a growing market as a result of the nation's abundance of natural gas supply, but one that is not directly relevant to the events of Winter Storm Uri.

- Storage providers supply underground storage, for system balancing and/or for later consumption.
- Local Distribution Companies (LDCs) supply and deliver the natural gas actually consumed by utility customers to those customers.
- Direct-connect end-users, such as power plants or large industrial users, take natural gas service directly from the transmission pipelines rather than from an LDC.

Q. HAVE THE PHYSICAL ACTIONS NECESSARY TO GET GAS FROM WELLS TO CONSUMERS CHANGED SIGNIFICANTLY THROUGH THE LIFE OF THE NATURAL GAS INDUSTRY?

A. No. However, the commercial operation of the industry changed radically in 1993, when the Federal Energy Regulatory Commission (FERC) implemented Order No. 636.

Q. WHAT DID ORDER NO. 636 DO?

A. Order No. 636 "unbundled" the industry, moving from the longstanding structure of transmission pipelines buying and selling the bulk of interstate gas and thus delivering to their customers a "bundled" product consisting of gas, transmission, and storage, to today's structure wherein transmission pipelines strictly transport and store gas as contract carriers, while buyers and sellers purchase and sell gas separately, moving it through the transportation and storage services provided by the pipelines. Thus, today, any question of supply reliability or behavior must be examined separately as between the sellers and the regulated transmission pipelines that physically move the gas.

Q. ARE THERE ANY OTHER ENTITIES IMPORTANT TO THE NATURAL GAS MARKET?

A. Yes. While generally not a physical contributor to the industry, marketing companies (marketers) serve a critical purpose. Marketers aggregate supply for commercial disposition and construct sales services that combine physical pipeline capacity, commodity supply, and storage in order to provide a large array of services to LDCs and power generators, thus essentially bringing together the disparate functions of the different market participants. Marketers may buy gas from producers, buy from consolidated pools supplied by many producers, buy from other aggregators or marketers, or provide asset management (AMA) services to utilities whereby the marketer takes control of the utility's contracted pipeline capacity and supply portfolio, managing it to deliver reliable service to the releasing utility, while also serving markets other than the utility to optimize the use of such contracts.

Q. IS THERE A COMMERCIAL STRUCTURE SURROUNDING THE TRADING OF PHYSICAL GAS?

A. Yes. There are many "market hubs," or "market centers," collectively referred to herein as "trading hubs," around the nation, several of which are directly relevant to the Minnesota natural gas market. These market hubs generally involve the intersection of pipelines with one another, or with key supporting facilities such as storage. Exhibit___(RGS-1), Schedule 3 is a schematic map of the major pipelines serving Minnesota and the six trading hubs relevant to this market.

Q. WHAT PIPELINES ARE IMPORTANT TO MINNESOTA?

A. As shown in Exhibit___(RGS-1), Schedule 3, these pipeline companies include Northern Natural Gas Company (NNG), Northern Border Pipeline Company (Northern Border), Great Lakes Gas Transmission LP (Great Lakes), Viking

Gas Transmission Company (Viking), and TransCanada Pipeline (TCPL). TCPL directly feeds Great Lakes and Viking and indirectly feeds both Northern Border and NNG. ANR Pipeline also provides support, which can enable Minnesota LDCs' access to multiple storage and other options through the Chicago market hub.

Q. WHAT ARE THE RELEVANT TRADING HUBS?

A. Four of the six trading hubs mentioned earlier are directly relevant to the Minnesota market: NNG Field/Market Demarcation (Demarc), the Kansas boundary between NNG's supply-area system and the market system that serves Minnesota; Ventura, Iowa (Ventura), where Northern Border and NNG intersect; Emerson, Manitoba (Emerson), where TransCanada feeds both Great Lakes and Viking; and NiGas in the Chicago area (Chicago), where extensive storage connects with the pipelines serving Minnesota. The other two trading hubs identified in Schedule 3, Empress, Saskatchewan and Dawn, Ontario, play a role in flows and pricing on TransCanada and Great Lakes, but are usually not directly involved with the Minnesota market.

Q. ARE THERE ANY OTHER KEY LOCATIONS RELEVANT TO THE MINNESOTA MARKET?

A. Yes. Also identified on Exhibit___(RGS-1), Schedule 3, by smaller dots, are Port of Morgan, Saskatchewan, where gas is delivered from Canada's Foothills pipeline into Northern Border, and Carlton, Minnesota ("Carlton"), where Great Lakes delivers gas into NNG and to other market participants in Minnesota. These locations are important to the physical function of the market but are not liquid market centers, meaning that gas is not sold and purchased at these locations like it is at the trading hubs.

B. Marketplace Transparency and How Prices Are Set

Q. IS THE U.S. NATURAL GAS MARKET RELATIVELY TRANSPARENT, WITH PREDICTABLE AND REVIEWABLE PROCESSES FOR HOW PRICES ARE SET?

A. Yes. The U.S. natural gas market is one of the most liquid and transparent markets in the world. In addition to the pervasive regulation of pipelines by FERC, trading in the unregulated gas commodity itself is subject to extensive reporting, observation, and analysis.

Q. PLEASE EXPLAIN.

A. Like other energy commodities, the sale and purchase of natural gas supplies and futures transactions take place both through one-on-one bilateral negotiated transactions directly between counterparties (including long-term contracts) and through open and transparent trading on organized/regulated exchanges, like the Chicago Mercantile Exchange (CME) and the Intercontinental Exchange (ICE). The natural gas futures market is generally referred to as the NYMEX market, after the New York Mercantile Exchange (NYMEX), where the standardized futures market was created. Subsequent to the creation of the NYMEX market, NYMEX was purchased and taken over by CME.

A subset of physical transactions, whether they happen on exchanges or directly between counterparties, are reported on a voluntary basis to price reporting agencies (PRAs), such as S&P Global Platts, Natural Gas Intelligence (NGI), Argus and others. PRAs then produce price indices, which are, in turn, used for index deals, or deals that are settled based on a published index price. About 84% of the physical daily and monthly deals in 2020 were done based on an index price. As noted, these deals are subject to constant and thorough reporting, observation, and analysis.

Q. HAVE NATURAL GAS SALES AND FUTURES TRANSACTIONS ALWAYS BEEN SUBJECT TO THIS PROCESS?

A. No. Prior to wellhead gas deregulation in 1989 and the restructuring of the pipeline industry in 1993, both wellhead prices and the actual pricing to pipeline customers were under FERC's direct control under the Natural Gas Policy Act of 1978 (NGPA) and the Natural Gas Act of 1938 (NGA). However, after those two pivotal changes in the late 1980s and early 1990s, the gas commodity market had little regulatory oversight until the early 2000s.

Everything changed in the wake of the Enron collapse and the concurrent chaos in the natural gas marketing and trading sector. These sales and futures transactions and the way they are reported to PRAs (and the PRAs themselves) became subject to a high degree of government oversight, through initiatives at FERC, at the Commodity Futures Trading Commission (CFTC), and through major legislation, in order to ensure the integrity and reliability of price indices, so that they will be representative of the market.

Q. CAN YOU PROVIDE EXAMPLES OF THIS INCREASED FEDERAL OVERSIGHT?

A. Yes. There are numerous requirements and activities involved:

- Every company involved in the business of buying and selling significant quantities of physical natural gas is required to report their transaction volumes and pricing mechanisms in some detail to FERC.
- FERC's 2003 Policy Statement on Natural Gas and Electric Price Indices put a program in place that requires companies that choose to report their trades to

trade publications and PRAs to follow a strict set of price-reporting guidelines, including the establishment of a formal code of conduct, requiring non-trading individuals to report the trades, and reporting all trades, not just a cherry-picked subset.

- The Energy Policy Act of 2005 (EPAct 2005) was passed and signed into law. EPAct 2005, Section 23(a)(1), directed FERC "to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce." It also provided both FERC and the CFTC with broad new enforcement power to police any gas-market manipulation in current transactions (FERC) or futures transactions (CFTC).
- In 2007, FERC Order No. 704 enacted regulations requiring natural gas market participants of any size to file a new form, Form 552, which provides aggregated volumes of natural gas purchases and sales, with quantities split out by types of pricing mechanism. It is an annual form that took effect in 2009 for calendar year 2008. Companies have been filing Form 552 each year since then. FERC compiles all the data and makes it available as a spreadsheet download.

Q. BEYOND PHYSICAL TRANSACTIONS ARE THERE OTHER IMPORTANT WAYS THAT NATURAL GAS IS TRADED?

A. Yes. The dynamic physical market is matched by an equally dynamic market in natural gas futures. The natural gas futures market is an important measure of the perceived value of natural gas in markets later in a year, or in other years further in the future.

Q. PLEASE EXPLAIN THE NATURAL GAS FUTURES MARKET, HOW IT OPERATES AND HOW IT IS REGULATED.

A. In the gas futures market, participants buy and sell standardized, monthly contracts (in lots of 10,000 million British thermal units (MMBtu)) on NYMEX. They settle with physical delivery to Henry Hub;[2] prices represent today's value for delivery in future months (not a forecast, but a traded value, meaning it is only as accurate as the opinions of the parties executing it).

The vast majority of these NYMEX contracts (98%) are offset by a matching buy or sell transaction in the futures market[3] that is executed before the delivery period occurs. As a result, these contracts do not end in the delivery of physical gas. A small percentage, however, are held by participants until the delivery date, ("held to expiry"), so that the contract holder must deliver or receive physical natural gas at Henry Hub. In this case, the contract has to have a delivery mechanism (the necessary pipeline capacity). This delivery mechanism represents a critical link between the futures contract and the physical spot market.

Q. CAN FUTURES TRANSACTIONS TAKE PLACE THAT DO NOT HAVE TO BE SETTLED AT HENRY HUB?

A. Yes. These transactions are referred to as "forwards," and can be transacted at any specified point on the pipeline grid.

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[2] The Henry Hub in Erath, Louisiana was established in 1990 as the reference point for the NYMEX contract, and has since become the primary trading reference point for the industry. Prices at other market points are spoken of in terms of "basis," the difference in price from the Henry Hub price.

[3] For example, a NYMEX contract to buy at a future date at a specified price will be followed by a later NYMEX contract to sell on the same date at a different price, executed prior to the date the gas would be delivered. Thus, in effect, the purchase and sale have taken place well before the delivery date, so that the original holder of the NYMEX purchase contract has finished the transaction before any gas moves physically under either contract.

Q. PLEASE DESCRIBE FORWARD CONTRACTS.

A. Forward contracts are similar to futures contracts because they are both agreements to buy or sell natural gas at a specific price at a date in the future. However, forward contracts can be for any quantity, delivered at any time, and must specify a delivery point. Generally, the prices could be stated either in absolute terms, but more typically, are stated as a positive or negative differential ("basis") from the Henry Hub price, generally based on transportation cost between the transaction market and Henry Hub. Moreover, forward contracts are bilateral, over-the-counter transactions made off-exchange. As such, unlike futures transactions which are on-exchange and regulated by the CFTC, forward contracts are not regulated by the CFTC (except with respect to the CFTC's market manipulation jurisdiction). Forward contracts can be combined with a NYMEX (Henry Hub) futures trade for the same period, to hedge physical volumes or trades.

Q. PLEASE DESCRIBE THE STRUCTURE AND NATURE OF THE MARKETS IN WHICH NATURAL GAS VOLUMES ARE PHYSICALLY DELIVERED FROM SELLER TO BUYER.

A. There are three primary structures (or markets) in which these deals occur:

(a) the daily physical spot market, in which natural gas is bought and sold for delivery the next day,

(b) the monthly spot market, where gas is sold on monthly contracts for the upcoming month during a period called bid week, historically being completed sometime during the last week prior to the first day of the month the gas is intended to flow, and

(c) long-term contracts, where gas supply is contracted under seasonal, annual, or multi-year deals.

Q. HOW ARE PHYSICAL TRANSACTIONS PRICED?

A. Regardless of the market type, trades can be fixed-price or can be based on a PRA index such as Platts' Gas Daily (Gas Daily) for daily prices, Platts' Inside FERC (Inside FERC) for monthly prices, or NGI. Fixed-price deals are those that are negotiated outright between counterparties and transacted directly or on an exchange such as ICE and then reported to PRAs for incorporation into their price indices. Index deals are those in which buyers and sellers agree ahead of time to settle the contract at the price published by the PRA at a specified location — typically a weighted average of all the trades reported for that location or the index price, plus or minus a differential to reflect the physical, contractual or market dynamics affecting the counterparties. Like futures contracts, physical transactions can also rely on basis, using the Henry Hub price plus or minus a differential to the location of the transaction, or the differential between locations ("basis differential"). This last option is particularly useful when the transaction location lacks enough liquidity for its price to be a reliable indicator of the market.

Q. WHICH TYPE OF PRICING HAS BEEN DOMINANT IN RECENT YEARS?

A. Exhibit___(RGS-1), Schedule 4 is a graphic breakdown of all transactions reported on Form 552 for calendar year 2020. Index deals have become the dominant pricing structure, since neither counterparty is making a wager on the difference between the contract price and a changing market during the duration of the agreement. By agreeing to an index deal, neither party assumes the risk of market movement. For that reason, index deals are popular among LDCs, producers, and end-users. Fixed-price deals of any duration have declined in use.

After the imposition of heightened scrutiny and regulation in response to the Enron-driven trading crisis of the early 2000s, the 2008 banking collapse caused a new set of rules to be put in place. The Dodd–Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) imposed a host of new requirements and restrictions on financial positions with elements of risk, most notably requiring very large credit foundations for fixed price deals. Prior to Dodd-Frank, financial traders such as banks did many fixed-price deals and most reported them to PRAs. However, fixed-price transactions by such non-industry participants declined precipitously once Dodd-Frank required them to backstop such financial positions. Thus, most fixed-price transactions today are performed by producers and those trading/marketing companies that survived the turmoil of the 2000s.

Q. HOW HAS THE PREVALENCE OF FIXED-PRICE TRANSACTIONS BEEN AFFECTED BY MARKET CONDITIONS?

A. Natural gas prices have been generally stable for long periods of time since physical abundance became a fact in the mid-2000s,[4] so often there is a relatively small difference between average index prices and fixed prices. Thus, fixed prices are often used simply for convenience. However, whenever periods of price volatility emerge or are expected, parties on both sides of a transaction become much more reluctant to set a fixed price as opposed to tracking an index.

[4] Natural gas physical abundance began to manifest itself as shale gas suddenly became economically feasible to extract, through the combination of hydraulic fracturing and horizontal drilling. Large volumes began to be produced in the 2005-2006 timeframe, and by 2008, shale gas was determined to be the source of a major turning point for the industry.

Q. HOW ARE TRANSACTIONS STRUCTURED ON THE DAILY, OR SPOT, MARKET?

A. Spot market transactions are for all volumes nominated/scheduled for next-day delivery up to the standard nomination deadline (1 p.m. Central Time) and are done directly with counterparties or via exchanges (e.g., ICE) for specific locations. On Friday, trades include nominations for flow on Saturday, Sunday and Monday (and if Monday is a holiday, then Tuesday as well).

Q. HOW AND WHEN ARE THESE TRADES REPORTED TO PRAS?

A. Companies involved in the market for physical natural gas (that choose to report their deals) must report all physical fixed-price deals completed by the 1 p.m. CT nomination deadline to the PRAs by 3 p.m. CT, including the related transactional data – volumes, prices, timestamp, etc., at the end of each trading day. The PRAs pull all the prices into database systems, developing a weighted average (or some other mathematical midpoint) of all reported trades. Some PRAs also have agreements with ICE to incorporate ICE trades or publish indices for ICE locations.

Q. HOW IS GAS TRADED ON A MONTHLY CYCLE?

A. A substantial volume of gas is also transacted in the month-ahead market. Monthly transactions are for delivery of specified volumes, based on expectations of baseload demand, effective on the first of the month (and thus called "FOM") and remain in effect each day of the upcoming month. Trades include fixed and basis deals. A basis deal will be stated as a fixed differential from a daily index price, so that the price varies over the course of the month, but its relationship to the published index does not. Bidweek trading typically happens during the last week of the month. At least one PRA, NGI, has shortened the bidweek reporting period to three days this year. PRAs publish the resulting bidweek FOM index on or around the first business day of the month in which the trades will flow.

C. Comparison of Gas Markets with Power Markets

Q. ARE THE NATURAL GAS MARKETS STRUCTURED AND OPERATED IN THE SAME MANNER AS THE ELECTRIC POWER MARKETS?

A. No. While there are similarities – many transactions in both markets are arranged the day before they take effect and risk management tools are similar – there are fundamental differences between the two markets. In organized markets such as the Midcontinent Independent System Operator, Inc. (MISO) that manages the electric power market in Minnesota, power trading and the management of transmission capacity happen within the same organization. In contrast, capacity in the natural gas market is managed by the pipelines themselves according to standardized rules imposed by FERC, whereas trading of the commodity happens on separate exchanges, primarily ICE, or bilaterally based on published indices or negotiated prices. As a result, there is not the same comprehensive overview and control of the market for both the commodity and the movement or storage of that commodity that exists in organized electric markets. A major part of the regulatory reason for this is that FERC determined in Order No. 636 that as long as pipelines could not exercise market power, the market for the gas commodity was competitive enough to allow market participants to negotiate their own contracts and market-based prices.

Q. WHAT IS THE MOST IMPORTANT DIFFERENCE BETWEEN THE MARKETS?

A. The most important and fundamental difference between the markets arises from the physical structure of those markets. The result is that the speed and frequency of transactions are far greater in electricity than in gas. In the electric market, trading during the "day of" happens throughout the day, working to balance the transmission systems in real time with actual trading of generation and load. This is necessary because electricity travels near the speed of light and must be used or stored at essentially the same time it is created, which means there is no ability of electric transmission systems to absorb short-term changes without adjusting generation or the load that relies upon it.

Natural gas markets, while dynamic, are far more static than electric markets, particularly during strained operating conditions such as a winter storm. Standardized pipeline nomination cycles only offer three opportunities to change nominations during the Gas Day (the period of twenty-four (24) consecutive hours, beginning and ending at 9:00 a.m. CT). Accordingly, the trading of the gas commodity follows this pipeline nomination structure, leaving limited ability to respond to changes during the day by buying or selling flowing supply. Utilizing these nomination opportunities, however, requires that a buyer can find willing trading partners, which can be difficult over the weekends where markets are not trading.

Q. HOW ARE THESE PIPELINE NOMINATION STANDARDS SET?

A. These standards were developed by the North American Energy Standards Board (NAESB), an industry standards-setting organization that recommends standards to FERC, which then requires pipelines to incorporate the standards in their tariffs. Figure 1 sets forth the standard NAESB nomination times.

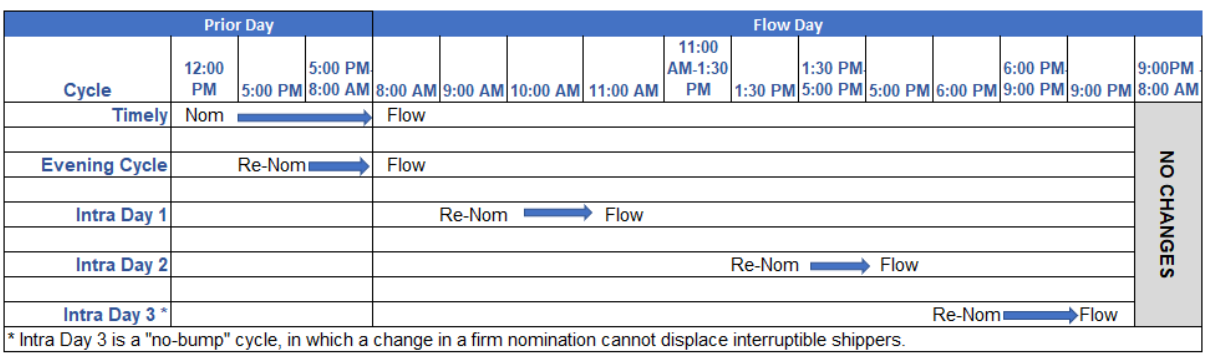
Figure 1—NAESB Nomination Timeline

Nomination Cycle	Nomination Deadline (CCT)	Scheduled Quantities	Time of Gas Flow	Bumping of IT
Timely	1:00 PM	5:00 PM	9:00 AM	N/A
Evening	6:00 PM	9:00 PM	9:00 AM	Yes
Intra Day 1	10:00 AM	1:00 PM	2:00 PM	Yes
Intra Day 2	2:30 PM	5:30 PM	6:00 PM	Yes
Intra Day 3	7:00 PM	10:00 PM	10:00 PM	No

Q. CAN YOU DEMONSTRATE HOW THESE FLOW THROUGH THE DAY BEFORE AND DURING FLOW?

A. Yes, Figure 2 is a graphic depiction of the nomination deadlines and flow times for the Timely, Evening, Intra Day 1, Intra Day 2, and Intra Day 3 nomination cycles.

Figure 2—Nomination Flow Chart



Q. DO PIPELINES HAVE MECHANISMS FOR OFFSETTING THIS RELATIVE RIGIDITY?

A. Yes. Pipeline customers have certain advantages that the electric market does not present. These advantages center around natural gas storage and the use of pipeline "line pack" (increases and decreases in pipeline pressures to respond to short-term variations in load). During lower-demand periods, when the pipeline is not experiencing strained operating conditions and has significant operating flexibility, pipelines are able to offer best-efforts hourly variation, reasonable tolerances on running an imbalance between receipts and deliveries, and services such as "park and loan," which allows customers to store or draw natural gas for a small fee, to accommodate timing differences between supply and demand. However, once a pipeline declares constrained operating conditions – which can include a "critical day," "system overrun limitation" (SOL) or a "system underrun limitation" (SUL) – imbalance and park and loan opportunities are generally prohibited, with customers exposed to very high penalties for taking too much natural gas, for being out of balance between receipts and deliveries, or for varying from taking their daily nomination in any pattern but ratably, one twenty-fourth each hour.

Q. IN THE SETTING OF SCHEDULED ACTIVITY FOR THE DAY AHEAD, ARE THERE OTHER DIFFERENCES BETWEEN ELECTRICITY AND NATURAL GAS?

A. Yes. Particularly relevant to the Winter Storm Uri situation over Presidents Day weekend, natural gas transactions on a Friday normally cover an entire three-day weekend, Saturday through Monday. When Monday is a holiday, the transactions cover four days, with minimal opportunities to change during the weekend. This is not a symptom of pipeline nomination schedules—pipelines adhere to the NAESB timeline seven days a week in accepting nominations and nomination changes. However, the market for the natural gas commodity has evolved to a point where purchases and sales are set for the full weekend on Friday, so that a natural gas customer such as an LDC often cannot find uncommitted supply during the weekend. Accordingly, the deals that have been struck on Friday are accompanied by pipeline nominations that match the purchase and sale contracts, remaining static over the weekend (including

Monday, and in the case of Presidents Day 2021, including Tuesday). This practice is quite different from the day-ahead electric market, which operates seven days a week.

Q. IS THERE ANY REGULATORY MECHANISM THAT COULD CHANGE THE PRACTICE OF WEEKEND-LONG DEALS IN THE NATURAL GAS INDUSTRY?

A. There is no regulatory mechanism, short of re-regulating the commodity market, that would change this structure.

Q. ARE THERE ANY PHYSICAL AND OPERATIONAL DIFFERENCES BETWEEN THE INDUSTRIES IN TERMS OF RELIABILITY?

A. Yes. In the electric industry, most situations that lead to energy-shortage blackouts can be restored by simply turning the power back on, as long as overall grid stability has not been compromised. However, if an LDC actually loses its system to the point that pressure becomes inadequate to supply its customers, the ensuing event is called a "relight." Every appliance on the system must be physically inspected and relit by appliance-service personnel to maintain safety, once pressure is restored. Failure to follow this relight procedure can result in situations in which pilot lights are extinguished, but old emergency-shutoff valves do not close (from, for example deterioration of the thermocouple that senses whether the pilot is burning). When that happens, air, which is heavier than natural gas, can enter the distribution system, creating potentially explosive situations inside the pipe. When I first entered the LDC business, I was told of such a situation in Boston in the early 1960s, when substantial portions of downtown Boston contained gas-air mixes of varying proportions.

Q. HOW EXTENSIVE IS SUCH AN INSPECTION AND RELIGHT OPERATION?

A. The time and difficulty involved depends upon the resources available to accomplish the restoration of service. No single LDC has enough appliance service personnel to address every appliance in every customer location on the system in any reasonable time frame. Thus, there are cooperative agreements among regional LDCs to lend appliance-service forces to each other in such a situation. I was told that the Boston relight took appliance service personnel from virtually every LDC on the East Coast, and still took over a month. A similar effort might not take as long these days, but the bottom line is that an LDC system supply failure is far more complex to correct than is an electric energy-shortage outage, and must be avoided at all costs.

D. Factors Affecting Natural Gas Prices

Q. WHAT FACTORS AFFECT NATURAL GAS PRICES IN A MARKET IN WHICH PRICES ARE COMPETITIVELY SET?

A. Starting with the general national market, there are many factors that affect prices, including the following:

- Weather predictions/outlook: If sellers predict severe weather, they will start bidding for any period longer than a day at high prices, anticipating a strong impact from demand growth. Meanwhile, buyers, especially utilities, need to build up their supply portfolios, and thus will be exposed to the high prices being demanded. If severe weather is also expected in supply areas, such that there could be an impact on supply availability to serve such strong demand, the upward pressure on prices for longer than a day becomes more severe.

- Total national storage inventory levels and activity: On Thursday of every week, the U.S. Energy Information Administration releases its observation of balances, injections, and withdrawals, often causing movement in prices. If storage levels are low, if injections are low or withdrawals are high, the market takes that as a sign that the market does not have as much flowing gas available as it needs. Thus, prices rise on both the selling and buying side. Conversely, if storage levels are normal or high, if injections are high or withdrawals are low, the market takes that as a sign that flowing gas exceeds demand.

- Current and projected production levels: Similarly, the balance between current and projected production levels causes market response in pricing just as supply/demand affects any commodity market.

- Demand for LNG exports: As the export of liquefied natural gas (LNG) has grown, it has placed significant demand pressure on the market, thus causing prices to rise somewhat. This year, the international prices for LNG deliveries have reached very high levels as compared with extremely low levels last year, reflecting an undersupply of LNG to the importing countries and putting demand pressure on U.S. terminals. There is not a direct translation of the international prices to the U.S. gas market, because of the finite capacity of terminals that can export LNG. However, the demand still causes upward pressure on the U.S. supply-demand balance, and thus raises prices.

- Exports to Mexico: Rapidly growing pipeline exports of natural gas to Mexico have put price-increasing pressure on U.S. supplies.

- Pipeline constraints to consuming markets: At the regional and local consumption level, and at the basin-specific production level, pipeline constraints and tariff provisions play an important role. When there is a constraint in the ability to reach demand markets, prices can rise very rapidly as supply at the terminus of the pipeline becomes a sellers' market. This happens almost every winter in New England and New York, where pipeline capacity is insufficient to meet winter peaks.

- Pipeline constraints from production basins: When pipeline capacity out of a production basin is inadequate to carry all the natural gas being produced, wellhead prices plummet, essentially becoming a buyer's market based on who can secure scarce pipeline capacity. This then has the effect of frustrating new development, eventually leading to the risk of production shortages.

- Pipeline tariff provisions and operational actions: The NAESB timeline creates a degree of rigidity that can make it difficult to respond to evolving circumstances. Further, when pipeline tariffs have exceptionally tight restrictions on imbalances and overruns, accompanied by large penalties for either over-taking gas by a customer or for the creation of imbalances by delivering more natural gas into the pipeline than is scheduled for re-delivery, pipeline customers will often buy excess supply and nominate somewhat high, scaling down during the intra-day cycles as possible, in efforts to make certain that they will not incur such penalties. If a large number of buyers in the same market area follow this practice, it can have the unintended effect of increasing daily prices. Especially in situations such as Winter Storm Uri, in which pipeline declarations of critical-day or strained operating conditions (as discussed below) sharply reduced any flexibility, purchasing gas at daily spot prices makes sense, even if that gas turns out to be unusually expensive, since the pipeline penalty for over-taking gas may be a significant multiple of those expensive index prices.

- Uncertainty of supply reliability: As was the case during Winter Storm Uri, when supply areas are severely impacted by a crisis, that will create uncertainty as to whether purchased and scheduled natural gas supply will arrive when needed. Such anticipated supply cuts under existing transactions can be extremely problematic, especially when demand is at unprecedented levels. Thus, buyers will typically arrange for more next-day supply throughout the crisis, to supplement their storage to compensate for potential cuts.

Q. WHICH OF THESE CONDITIONS AFFECTED PRICES DURING WINTER STORM URI?

A. During Winter Storm Uri, which affected the entire midcontinent, extending to important supply areas in Oklahoma and Texas, the primary factors that acutely impacted market prices were loss of production in Texas and Oklahoma, tight pipeline tolerances, and uncertainty as to the stability of the flowing supply that had been scheduled. In the interstate market, the rigidity of the NAESB timeline and the pipeline-specific restrictions discussed in the next section also played a role.

E. Interstate Gas Pipeline Tariffs

Q. HOW DO YOU ADDRESS GAS PIPELINE TARIFFS?

A. I concentrate on three directly relevant provisions of the tariffs for the pipelines identified earlier, NNG, Northern Border, Great Lakes, and Viking: (1) the nomination timelines, (2) the volumetric tolerances as to variations from scheduled quantities, and (3) the level of penalties for exceeding scheduled quantities during strained operating conditions.

Q. WHAT IS THE SIGNIFICANCE OF THESE PROVISIONS?

A. They define the options that were available (or not available) to Minnesota utilities as the unprecedented impact of Winter Storm Uri unfolded. They also provide the structure within which all potential sellers or buyers had to operate for purchased natural gas to actually reach consumers.

Q. PLEASE SPECIFY THE TERMS OF THE FOUR PIPELINES' TARIFFS AS YOU INDICATED.

A. Table 1 summarizes the five areas for the pipelines.

Table 1—Key Tariff Provisions of Relevant Pipelines

	NNG	NBPL	GLGT	VGT
Nomination Timeline	NAESB 1_/	NAESB	NAESB	NAESB
Variation from Scheduled Quantites	1.5 X Spot for 2%, 1.75 X Spot for next 3%			
Penalties for Unauthorized Overrun	2 to 3 times Market Area Spot for the affected Day	3 x Chicago city gate daily	2x average daily midpoint price for Emerson Viking GL Platts Gas Daily	Outside 2% allowable variation 3x the higher of midpoint for

1_/ NNG does offer some degree of further flexibility, but it is not meaningful for protecting against late-day supply inadequacy.

All four pipelines tariffs contain straightforward application of the NAESB Timeline set forth in Figure 1. All four also have harsh penalties for exceeding scheduled quantities, two to three times the relevant index price. For the two dominant pipelines, NNG and NBPL, this means two to three times Demarc or Ventura, both of which reached high levels, so that multiples of those prices could be as much as $600.

Q. WHAT ARE THE IMPLICATIONS OF THESE RESTRICTIONS AND PENALTIES?

A. The implications are that during a strained operating condition, and particularly one accompanied by the extremely high prices caused by Winter Storm Uri, it would be far more expensive for LDCs to exceed their scheduled quantities because of an unforeseen cold snap or other change in demand or the supply mix than to purchase enough flowing, scheduled supply to ensure not exceeding the scheduled quantity. While these operating decisions are individual to each LDC as part of each company's operating plan and portfolio, the incentives to avoid penalties that would cost their customers much more than the additional flowing supply are clear.

F. Risk Management

Q. WHAT RISK MANAGEMENT TOOLS ARE AVAILABLE FOR BUYERS IN THE NATURAL GAS INDUSTRY?

A. The natural gas industry uses both physical and financial tools to manage risk. The financial tools are essentially the same as in any financial sector: futures, puts, calls, and swaps. These are then organized into various structures such as hedges and collars. As explained earlier, these instruments have been heavily influenced by (and more restricted because of) the Dodd-Frank response to the financial and real-estate crisis of 2008.

Physical risk-management tools are specific to the natural gas industry, including a variety of contracts for physical gas, including fixed-price contracts (either daily or longer-term), full-month prices established during "bid-week" at the end of the prior month, and long-term formula contracts, as well as physical storage. The use of these tools is heavily influenced by the interaction of the operational needs of the participants, particularly for utilities with a public-service commitment to reliability.

Q. ARE THE FINANCIAL TOOLS YOU LISTED WIDELY USED IN THE NATURAL GAS INDUSTRY?

A. Yes, but primarily by commercial participants in the market other than utilities. The exceptions are that utilities do use the natural gas futures market as a hedge, including the "collar" approach, wherein prices follow the daily market but are constrained by a maximum and a minimum level.

Q. COULD FUTURES HEDGES AND COLLARS BE HELPFUL IN THE SITUATION POSED BY WINTER STORM URI?

A. They could be, if there are interested counter-parties, and if they can be set up early enough to capture attractive prices and to be coordinated with the actual supply requirements during the storm. A major issue is the fact that, as will be discussed later, weather conditions during Winter Storm Uri deteriorated significantly as compared with forecasts, so that sizing hedges or collars sufficient to provide enough supply would not have been feasible weeks or months prior to the event. In particular, established monthly or longer purchases or futures-based hedges have limits in their usefulness during volatile winter weather. Most utilities nationwide of which I am aware restrict such arrangements to the quantities of gas they are certain they will take during the period of the purchase contract or future physical availability, in that over-committing to such static arrangements, wherein all the gas must be taken can be extremely costly if all the gas is not needed—it often must be disposed of at greatly disadvantaged prices in order to honor contract commitments. Thus gas purchased on a daily basis, which is responsive to weather, is by far the preferred mechanism for dealing with the unpredictable behavior of winter weather.

Q. HOW USEFUL ARE VARIOUS PHYSICAL RISK-MANAGEMENT TOOLS TO DEALING WITH AN EVENT SUCH AS WINTER STORM URI?

A. The tools such as monthly pricing, mid-month fixed-price contracts, or longer-term formula contracts (e.g., an inflation escalator or Inside FERC First of Month pricing plus a fee, or daily index pricing plus a fee) could be useful if employed prior to general knowledge of the severity of the storm. Once that severity became clear (to both buyers and sellers), the cost of securing any kind of price protection would become impossible, in that sellers would not take the risk. In the case of Winter Storm Uri, any arrangements made prior to the twelve days leading up to the storm would have relied upon weather forecasts that significantly understated the degree of cold weather that would be experienced, and thus the necessary fuel requirements. Additionally, the impact of Winter Storm Uri on supply areas in Texas and Oklahoma was not anticipated throughout the industry.

Q. IS THE ONLY USE OF STORAGE AS A FINANCIAL HEDGE, AS YOU DESCRIBED ABOVE?

A. No. Natural gas storage has multiple purposes and uses, the relative importance of which varies depending on current operational conditions.

Q. WHAT ARE THE PURPOSES AND USES OF STORAGE HELD BY UTILITIES?

A. Storage constitutes part of the economically-based overall plan for meeting heating-season requirements. Not only is its service charge often less expensive than paying for the same peak capacity as 365-day, year-round firm pipeline capacity, it also allows generally less expensive summer gas to be stored and withdrawn in the winter, when commodity prices are higher, thus saving gas cost as compared with flowing supply.

Throughout the year, storage has another critical function, system balancing. For example, it can be used to make up for imbalances in flows as compared with scheduled volumes, to build up line pack when, for example, a power generator needs high pressure to come online, and can serve other operational needs. It can also be a key backstop in the event of a supply failure or a system upset.

Q. HOW IS STORAGE A PHYSICAL HEDGE?

A. Natural gas stored underground has already been purchased at seasonal prices that are generally lower than the prices experienced during severe winter weather. Thus, being able to control a substantial volume of low-priced gas and use it as necessary to displace more expensive supply can be of significant value as a hedge. However, as will be explained, this role can sometimes be overtaken by events, requiring the holding back of storage for operational reasons.

Q. DOES THE RELATIVE PRIORITY OF THE USES OF STORAGE CHANGE DURING AN EXTREME WEATHER EVENT SUCH AS WINTER STORM URI, AND IF SO, HOW DO THEY CHANGE?

A. They can change, based on the specifics of the situation and the operational circumstances faced by the company involved. During an event such as Winter Storm Uri, purposes and priorities can shift rapidly. Storage is the primary asset over which the utility has direct control in order to maintain system integrity in the face of volatile demand and uncertain supply. It is the tool with which the utility maintains the necessary pressure to avoid damaging service outages or even the catastrophic loss of pressure in its entire system. Particularly in an unprecedented event such as the supply impact of Winter Storm Uri, storage deliverability (the rate at which gas can be withdrawn) can be an important constraint on the use of storage for cost moderation. The problem is that, as inventory is drawn down from storage, the storage field's pressure declines and so deliverability (the rate at which the utility can receive gas from the field) declines. Usually such decreases in deliverability are specified as "ratchets," specific drops at intervals, rather than a continuous decline with inventory. Thus, the importance of the reliability constraint on storage use is a function of the severity of the weather event, and the extent to which the constraint can modify behavior depends on the specifics of the ratchet pattern.

Q. WHEN COMMODITY PRICES REACH THE EXTREMELY HIGH LEVELS EXPERIENCED DURING WINTER STORM URI, SHOULD GAS BE WITHDRAWN IN LIEU OF PIPELINE PURCHASES, IN ORDER TO HOLD COSTS DOWN?

A. As noted, storage withdrawals can certainly help moderate the effect of such high prices, but only within the reliability constraint described above. The operational importance of storage can far supersede economic impacts if the reliability constraints are reached or exceeded. Ultimately, the key is that storage must be actively managed according to an all-asset plan that meets the utility's operational profile.

Q. HOW IS STORAGE ACTIVITY PLANNED AND MANAGED?

A. Usually, there is a fairly constant level of storage withdrawal during the heating season, designed to maintain inventories and thus withdrawal capabilities at sufficient levels to respond during the coldest portions of the heating season—that is, over-withdrawal can deplete inventory too fast to retain the peaking capability of storage,[5] so the quantities called upon regularly may tend to be conservative. However, the management of storage is very fact-specific to each individual utility, sometimes providing for maximum withdrawals during high-load periods, sometimes for the purchase of more flowing gas in lieu of storage withdrawals. Thus, it is not feasible to make one generic statement as to the best way to manage storage.

Additionally, some storage areas relied upon by Minnesota utilities are "aquifer" storage facilities, wherein natural gas is injected into deep saline formations, displacing the water into the surrounding porous rock, and then using the return of the water to enhance delivery pressure. One characteristic of aquifer storage is that if gas inventory is left in the ground for excessive periods, it begins to migrate into the water and be lost. For this and other reasons, storage service providers generally require cycling and withdrawal by the end of the winter heating season.

III. LDC GAS PROCUREMENT PRACTICES

Q. PLEASE DESCRIBE YOUR APPROACH TO EXPLAINING THE GAS PROCUREMENT PRACTICES OF LDCS.

A. Using a combination of my own experience of working for an LDC and serving many LDCs as a pipeline executive, combined with experience gathered from RBN's network of experienced LDC gas buyers, and interviews with gas-supply managers across multiple utilities nationwide, I describe a "typical" LDC or

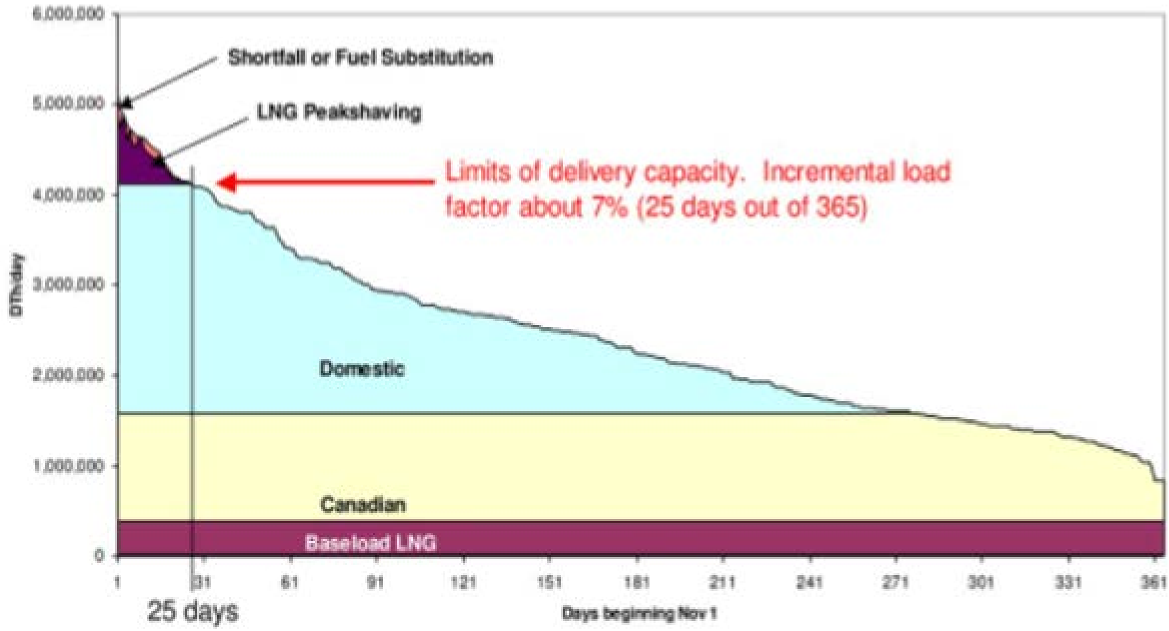
[5] Because the storage services involved here are purchased from third parties, this decline in deliverability with inventory decline is expressed in "ratchets" specified in the service providers' tariffs, whereby available withdrawal capability drops by discrete amounts in steps, at the various decreasing levels of inventory.

combined LDC/Power company in terms of how it approaches supply needs on an annual, seasonal, monthly, and daily basis. I will also describe the tools available to handle swing requirements including storage, pipeline flexibility, selection among pipeline suppliers, and curtailment of interruptible customers to maximize reliability.

Q. WHAT STEPS DOES AN LDC GO THROUGH IN ESTABLISHING ITS GAS SUPPLY PORTFOLIO?

A. First, on an annual, seasonal, and monthly basis, the LDC analyzes its projected demand and how much of that will be met by baseload (constant) supply, storage, daily market purchases, any "swing" available from term sellers on the pipelines that supply the LDC and, finally, any peak shaving capability. Based on that analysis, the LDC usually will use a request for proposals process to contract for "term" gas supply, meaning longer than a day and usually longer than a month, in two layers, an annual baseload and a heating season baseload. These are quantities of gas expected to flow every day of their contract terms. For levels of demand above what is met by the baseload quantities, which are less predictable and much more sensitive to weather, the LDC will rely on the daily market, storage withdrawals, term contract swing and peak shaving as needed each day. Generally, how much of the LDC's demand will fall into each category is determined by a "load duration curve," representing the expected behavior of load during the heating season, with baseload supply at the bottom, planned storage withdrawals next, daily purchases next, along with some combination of higher storage withdrawals, term contract swing and peak shaving meeting the daily fluctuations and highest-demand periods. Figure 3 is an example of a load duration curve.

Figure 3—LDC Load Duration Curve



Q. HOW IS STORAGE PLANNED AND OPERATED?

A. Storage planning and operation is discussed above, in Section II F., Risk Management.

Q. WHAT IS PEAK SHAVING?

A. Peak shaving refers to facilities such as propane-air or stored LNG liquefied from earlier flowing pipeline supply, that can supply high, controllable deliverability for short periods of time, so-called "needle peaks" in demand. While they can be useful in maintaining reliability in short periods of high demand, their total supplies are often limited, and some—especially propane-air—face constraints based on chemical compatibility with flowing natural gas supplies. Therefore, they are generally used for intra-day balancing to address acute demand spikes and as one of the resources of last resort when conditions near or reach a design day, rather than as regular sources of supply.

Q. WHAT IS TERM CONTRACT SWING AND HOW IS IT USED?

A. "Term contract swing" is the right in some term contracts to vary deliveries based on system conditions. Such provisions must be coupled with pipeline provisions that allow the deliveries to take place physically. However, once called upon, swing gas has no more hourly flexibility than non-swing purchases, it must be taken ratably throughout each day, based upon that day's daily volume. These contracts require the same volume for each day over a trading period such as a weekend or holiday.

Q. WHAT ARE THE BENEFITS AND LIMITS OF THE CURTAILMENT OF INTERRUPTIBLE LOAD IN MEETING HIGH-LOAD WINTER PERIODS?

A. The primary benefit is that an interruptible load is one that the LDC can require to stop taking gas, knowing that the customer involved would not have signed up for interruptible service without some alternative, such as an alternate fuel stored on-site. However, the limits are very company- and customer-specific, in that the utility simply having the contractual and tariff right to interrupt service may not be able to be confirmed or enforced quickly if there is not sufficient remote metering or remote flow control capability. Thus, how well interruption of such loads can relieve a system depends very much on what measures are in place to guarantee compliance. In many markets, the smaller an interruptible customer is, the less likely that expensive metering and control facilities will have been installed, highlighting the company-specific nature of the resource.

Q. OF THESE VARIOUS SOURCES OF NON-TERM SUPPLY, ARE THERE VARIATIONS IN THE DEGREE TO WHICH AN LDC CAN RELY UPON THEM?

A. Yes. Of the several sources, only storage, curtailment of interruptible load (with the caveat explained above) and peak shaving are under the direct control of the LDC, and even in the case of storage, that control depends on where the storage is and who operates it.[6] Term gas swing can be frustrated by a pipeline's ability to deliver it during strained operating conditions or critical days. Daily purchases depend on there being a willing seller that can actually deliver on short notice, a potential problem during a weather crisis. Some of this uncertainty can be dealt with by entering into "call" contracts, whereby the LDC can demand gas from a seller, but the gas is still priced at daily index-based prices.

Q. IS THE SELECTION OF THESE VARIOUS LAYERS OF SUPPLY PRIMARILY DRIVEN BY ECONOMICS?

A. In my experience, the original population of the load duration curve and the plan for the winter is generally based on relative economics, known or estimated, of the various sources of supply. However, once a particularly severe weather event strikes, by far the primary concern is reliability. Thus, for example, it *could* be reasonable for an LDC to buy daily gas that is more expensive than available storage withdrawals, *if* such storage withdrawals would diminish the ability to respond to unforeseen spikes in demand, or unforeseen failures of physical supply. The utility must stand ready at all times to meet current load and be prepared to meet future load, in the face of rapidly changing, often unpredictable circumstances—for example cuts in flowing supply, even under term contracts, because of supply-area upsets such as freeze-offs. In a

[6] With the exception of some storage owned by CenterPoint Energy, the storage services relied upon by the Minnesota utilities are not owned, but are services contracted with third parties whose own tariff conditions determine availability.

severe weather event, the LDC must focus on maintaining reliable service as demand or supply conditions change, while also remaining prepared to deal with other cold weather conditions in the remainder of the heating season.

Q. CAN AN LDC USE SHORT-TERM OR EMERGENCY CONSERVATION APPEALS TO ITS CUSTOMERS TO REDUCE THEIR NEED TO PURCHASE SUPPLY AND TO INDUCE SAVINGS ON EXPENSIVE NATURAL GAS SUPPLIES?

A. An LDC can certainly issue requests for conservation, but as is explained below, they would not reasonably reduce their purchases of supplies and will be unlikely to generate material savings on gas cost.

Q. ARE SUCH APPEALS GENERALLY USED TO HOLD DOWN THE COST OF GAS, AS OPPOSED TO DEALING WITH OPERATIONAL CONDITIONS?

A. No. In my experience, the large majority of LDCs reserve such appeals to situations in which the reliability of service or system integrity are threatened.

Q. IS THERE A REASON FOR SUCH LIMITED USE OF CONSERVATION APPEALS?

A. Other than my personal observation, I received a great deal of information on LDC emergency decision making both running and consulting for a post-9-11 project assessing the vulnerability of east-coast energy networks to terrorist action against supplying pipelines.[7] An important part of the effort was to

[7] The project began under my supervision on behalf of the pipeline trade association, INGAA, and the LDC trade association, AGA. Then, it was ultimately taken over by the U.S. Departments of Energy and Homeland Security, supervised by a steering committee of many stakeholders including LDCs and state regulatory commissions. I was a member of that steering committee and was also engaged as a consultant by DOE's contractor, the Gas Technology Institute. The overall study itself was non-public, but those of us involved were free to share input we received in parts of our inquiry. Ultimately, we covered the entire nation, but the most in-depth interviews were with the first group, gaining understanding particularly from the New York companies that had dealt with the public-safety and energy-supply issues after the 9-11 attacks.

interview the gas-supply operators in LDCs from New York City to North Carolina. An important area of inquiry was what level of conservation could be achieved before the U.S. government would need to step in and allocate scarce supplies. All of the companies interviewed anticipated being able to cause substantial conservation of both gas and electricity if the triggering event were a crisis the equivalent of the 9-11 attacks. In less severe situations, such as reaching the limit of pipeline deliverability (a genuine threat in New York), they were less optimistic. However, one theme was clear – to achieve meaningful conservation, a major emergency threatening reliability, life and property was needed for consumers to take the appeals seriously, and such appeals could not be frequent, or for reasons other than system reliability, without becoming routine and disregarded. Thus, the utilities consistently withheld such appeals for serious operational emergencies.

Q. IF AN LDC MAKES PUBLIC APPEALS FOR CUSTOMERS TO CONSERVE (DIALING BACK THERMOSTATS, ETC.), WOULD IT BE ABLE TO THEN PURCHASE LESS SUPPLY OR OTHERWISE SHED SUPPLY COST?

A. No. There is no practical way for such a conservation appeal to work to avoid supply cost in the short-term. While conservation can be generally helpful for system operations and can create long-term savings, a specific conservation appeal will not impact managing natural gas supply during volatile weather and market conditions.

Q. WHY WOULDN'T CONSERVATION APPEALS ENABLE THE LDC TO PURCHASE LESS GAS SUPPLY?

A. The response to conservation appeals is the aggregate of a very large number of individual decisions, decisions that can change at any time, e.g., conserving during the day but then deciding to increase usage in the evening. In purchasing gas the morning before the Gas Day, it is essential to reliability that the LDC purchase enough supply for what its customers can take, not what it hopes they will take. Thus, the supply nominated on pipelines at 1:00 p.m. on the day before flow cannot be reduced based on an unenforceable expectation of conservation. As the Gas Day begins, even if conservation is observed in the early hours, there is no guarantee that it will continue in later hours, meaning that the LDC cannot reduce its daily nomination and release supply to sell in the market without reasonable certainty that lower consumption levels will continue during the day. To do so and then face increased consumption on a cold day when all resources are employed would risk a failure of service. LDCs' demand forecasts are based on past customer behavior and experience in similar circumstances. No LDC can (or should) bet on sudden changes in customer behavior when that risks the ability to serve all customers, especially when that can quite literally have life-or-death consequences. It should also be noted that the inability of a natural gas LDC to factor short-term conservation appeals into its purchasing decisions is quite different that the situation faced by an electric utility that has the ability to make real-time adjustments to changes in load.

Q. COULD THE LDC PURCHASE SUFFICIENT SUPPLY FOR THE NORMAL LOAD, THEN, IF CONSERVATION HAD CONTINUED SUFFICIENTLY FAR INTO THE GAS DAY, SELL EXCESS SUPPLY TO OFF-SYSTEM BUYERS?

A. No. Based on my experience, a determination that excess load exists could not be made until the factors that affect consumption are finished changing for the day, at the earliest, sometime in the early to mid-evening. For any excess gas to be sold at that point, the buyer would need additional firm transportation in order to receive the gas. The last opportunity to change nominations during the Gas Day occurs at 7:00 p.m., effective at 10:00 p.m. However, that third intraday nomination opportunity is "no-bump." A firm pipeline customer cannot increase its nomination during that cycle if doing so would displace any other shipper's flow. During severe winter weather, pipeline capacity is usually fully utilized, meaning that it is impossible to increase a nomination without displacing other shippers, and thus impossible for a buyer of released gas to take it. Awareness of this restriction, coupled with the reality that by 7:00 p.m. commercial parties on both the buy and sell side have made their deals for the day, means that there is no nighttime market.

Q. IF ANY PIPELINE TO WHICH THE LDC AND ITS BUYER HAS ACCESS IS <u>NOT</u> RUNNING AT CAPACITY, COULD THAT PROVIDE AN OPPORTUNITY FOR LATE-DAY OFF-SYSTEM SALES TO A BUYER ON THAT PIPELINE BY USING THAT PIPELINE'S INTRADAY 3 NOMINATION CYCLE?

A. That would be very unlikely. If a pipeline is not full in the middle of a winter storm, it is because there is no more market to be served on that pipeline. Certainly, such an unlikely outlet could not be relied upon for planning purposes.

Q. WHAT OPTIONS DOES AN LDC HAVE FOR DISPOSAL OF EXCESS GAS SUPPLY?

A. When an LDC's load drops below its committed gas-supply level, it is confronted with gas supply that has to be taken during the Gas Day, and can really only be disposed of through storage operations or by running a "pipeline owes" imbalance on the pipeline. As noted earlier, during constrained days, pipeline imbalance-management provisions may restrict both "shipper owes" <u>and</u> "pipeline owes" imbalances. However, even if the pipeline can absorb the excess gas as a "pipeline owes" imbalance, there is usually not a reliable way to get the gas back the next day, or at any point during the extreme weather event because pipelines generally restrict or prohibit imbalance payback during a constraint day. As for modifying storage operations, either injecting the gas into storage or reducing storage withdrawals might help operationally if there are no constraints in moving back and forth to storage, but would not save gas cost—the day's gas would still be purchased, with no offset from off-system sales.

Q. IF CONSERVATION APPEALS DID NOT WORK TO REDUCE CONSUMPTION, COULD AN LDC ACTUALLY CURTAIL DELIVERIES TO ITS CUSTOMERS?

A. As a practical matter, beyond curtailing interruptible end-users either through direction or through actual hardware such as cutoff valves, the LDC could not curtail its customers. I was active through the gas shortages of the 1970s when "curtailment" was a major topic for approximately a decade. The only curtailment that took place to any meaningful extent was in the quantity of gas delivered by pipelines to the LDCs. No LDC of which I was aware ever tried to force its firm customers (particularly residential and small commercial) to reduce consumption. Overall, in the half-century I have been involved with the industry, I have never seen that done or attempted to be done.

IV. WINTER STORM URI AND NATURAL GAS MARKET IMPACTS

Q. PLEASE DESCRIBE WHAT WILL BE COVERED IN THIS SECTION OF YOUR TESTIMONY.

A. I will cover Winter Storm Uri and its impacts on the market based on the following topics:

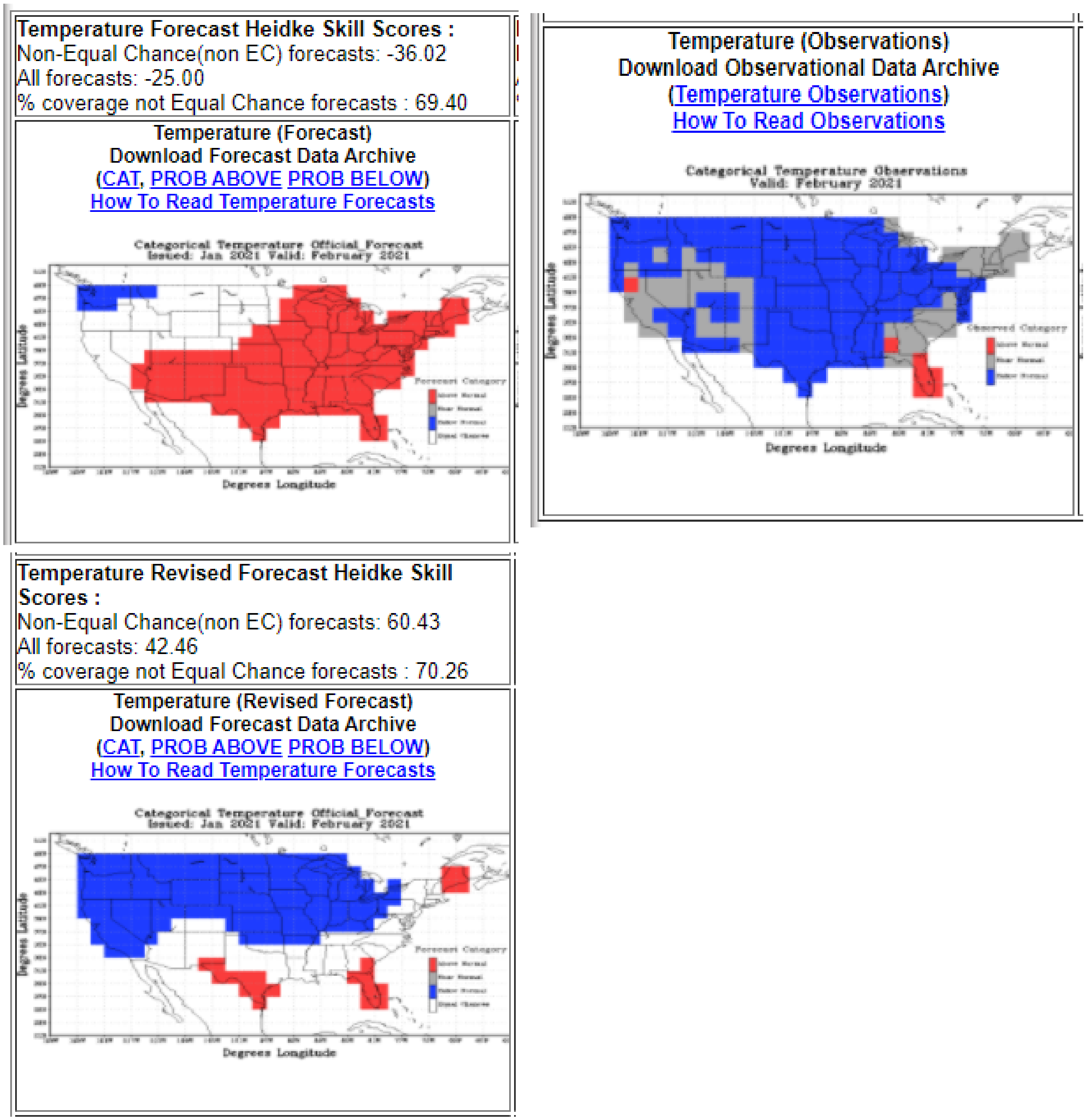
1. Weather forecasts prior to February (when monthly deals were consummated), at the beginning of February, and day by day during the Winter Storm Uri crisis, comparing actual experience with the forecasts.
2. Loss of supply in Texas and Oklahoma relevant to Minnesota, day by day during the crisis, focusing in particular on the Permian Basin in Texas.
3. The market response to forecasts, particularly at February 11-12 when supply arrangements were being made for the long weekend (weekend deals typically run from Saturday through Monday, but because of the holiday, all flowing-supply arrangements were for Saturday through Tuesday).
4. The impact on prices of the market response to forecasts and real-time experience.
5. A comparison of the impact on utilities and consumers in Minnesota, with the impact in Texas.

A. Weather Forecasts and Experience

Q. PLEASE DESCRIBE THE RELEVANT WEATHER FORECASTS AND MEASUREMENTS LEADING UP TO, AND DURING, FEBRUARY AND WINTER STORM URI.

A. Figures 4 through 6 present three sets of weather forecasts, with comparison to actual weather. Figure 4 includes two forecasts and actual experience, from the National Weather Service (NWS). Figure 5 is a table of specific local forecasts and experience from the Weather Desk, a service we use at RBN that is generally consistent with other forecasts. Figure 6 is a table of specific forecasts local to Minnesota from DTN, a global company based in Minneapolis, relied upon in many locations around the world, including some upper-Midwest utilities.

Figure 4—NWS Forecasts and Experience



Q. PLEASE DESCRIBE THE NWS RESULTS IN FIGURE 4.

A. In January, when buyers were contracting for monthly supplies for February, initial NWS forecasts, represented by the first map on Sheet 1, anticipated

February to be warmer than normal, as January had been. At the end of January, (second map, below the first), the forecast was revised to show the upper Midwest as being colder than normal, which would indicate increased demand. However, predictions that the southern producing states, particularly Texas and Oklahoma, would be faced with extreme weather did not occur until plans were being made for the long weekend on or about February 8, 2021. Thus, even in late January, it appeared that, while requirements would be higher in February than expected earlier, abundant supply at reasonable prices would be readily available in the daily market. This condition would not have been materially different from all the prior winters when there was no price fly-up.

As is now well-known, the producing states did, in fact, experience a massive, unprecedented weather emergency that cause significant reductions in available supply and price spikes during the several days in the middle of the month. This temperature experience is depicted in the actual conditions posted by NWS on February 17, the right-hand chart.

Figure 5—Weather Desk Predictions and Experience

			FLOW DATES									
			FRIDAY FEBRUARY 12		SATURDAY FEBRUARY 13		SUNDAY FEBRUARY 14		MONDAY FEBRUARY 15		TUESDAY FEBRUARY 16	
			Minneapolis Temperature	Difference From Prior Forecast	Minneapolis Temperature	Difference From Prior Forecast	Minneapolis Temperature	Difference From Prior Forecast	Minneapolis Temperature	Difference From Prior Forecast	Minneapolis Temperature	Difference From Prior Forecast
FORECASTS	Forecast of January 31, 2021	HI	20		21		23					
		LO	4		5		6					
		MDPT	12		13		15					
	Forecast of February 4, 2021	HI	5	(15)	9	(12)	16	(7)	21		23	
		LO	(10)	(14)	(8)	(13)	(1)	(7)	5	NA	7	NA
		MDPT	(3)	(15)	1	(13)	8	(7)	13		15	
	Forecast of February 6, 2021	HI	2	(3)	9	0	15	(1)	17	(4)	18	(5)
		LO	(17)	(7)	(11)	(3)	(2)	(1)	1	(4)	2	(5)
		MDPT	(8)	(5)	(1)	(2)	7	(1)	9	(4)	10	(5)
	Forecast of February 8, 2021	HI	(2)	(4)	(4)	(13)	1	(14)	9	(8)	16	(2)
		LO	(9)	8	(13)	(2)	(18)	(16)	(11)	(12)	1	(1)
		MDPT	(6)	2	(9)	(8)	(9)	(15)	(1)	(10)	9	(2)
	Forecast of February 10, 2021	HI	(1)	1	(1)	3	(4)	(5)	6	(3)	12	(4)
		LO	(8)	1	(12)	1	(15)	3	(16)	(5)	(5)	(6)
		MDPT	(5)	1	(7)	2	(10)	(1)	(5)	(4)	4	(5)
ACTUAL	Actuals Reported on February 17, 2021	HI	(4)	(3)	(3)	(2)	(4)	0	0	(6)	12	0
		LO	(13)	(5)	(12)	0	(19)	(4)	(17)	(1)	(15)	(10)
		MDPT	(9)	(4)	(8)	(1)	(12)	(2)	(9)	(4)	(2)	(5)

Q. PLEASE DESCRIBE THE WEATHER DESK PREDICTIONS AND EXPERIENCE SET FORTH IN FIGURE 5.

A. The Weather Desk table shows Minneapolis high, low, and midpoint temperatures for February 12-16, as forecast from January 31 through February 10, and the actual experience reported on February 17. I built the table from extracts from the larger Weather Desk data base.

Q. WHAT DOES THE TABLE INDICATE?

A. The table indicates that out of 18 forecasts from February 4 through February 10, only 5 exhibited equality with, or warmer temperatures as compared with their prior forecast. All others showed temperatures below the previous forecast. Additionally, the actual experience reported on February 17 exhibited no temperatures that were warmer than the last forecast and only 3 out of 15 data points that were equal to the last forecast. The other 12 data points were uniformly colder than the forecast.

Q. WHAT ARE THE IMPLICATIONS OF THIS DATA?

A. The implications are that, as of the morning of February 12, when commitments were made that would define the available supply through February 16, a decision to commit to more natural gas supply than the weather forecast indicated was the correct one. Demand was necessarily higher than forecast at February 10. In addition, because there were no warmer-than forecast temperatures, losses of supply because of supply-area *force majeure* issues would not be offset by any weather improvements in the consuming market.

Q. PLEASE DESCRIBE THE DTN FORECASTS AND EXPERIENCE DEPICTED IN FIGURE 6.

A. This table from the DTN weather service, which is based in Minnesota but used not only by Minnesota utilities but, according to the DTN website, around the world, follows three diverse points within Minnesota, Minneapolis, Rochester, and Bemidji, providing forecast and actual average temperatures. As noted, the forecasts are provided on the last business day prior to the Gas Day, which means that February 11 was the forecast for February 12, then February 12, being the last business day prior to the long holiday, was the forecast for February 13-16. The forecast issued Tuesday, February 16 applied to February 17. Green blocks indicate the days when actuals were equal to or warmer than forecasts. Yellow blocks are the days when temperatures fell below the operative forecast.

As shown, on February 12, when there was as yet no current crisis, Minneapolis was slightly warmer than predicted. On February 17, after the conclusion of the four-day crisis weekend, all three points were warmer than predicted. On February 13, Rochester's average temperature predicted on the prior day was equal to the forecast. Other than those five situations, every other day at every point was colder than forecast, with the one exception of Rochester on Sunday, February 14, when it was two tenths of a degree warmer than the forecast.

Figure 6—DTN Forecasts and Experience

		Minneapolis Int Avg Temp		Rochester Avg Temp		Bemidji Avg Temp	
Forecast Date 1_/	Flow Date	Forecast	Actual	Forecast	Actual	Forecast	Actual
February 11, 2021	February 12, 2021	(7.40)	(7.10)	(8.40)	(8.90)	(19.20)	(23.50)
February 12, 2021	February 13, 2021	(7.00)	(9.60)	(11.50)	(11.50)	(20.00)	(22.20)
February 12, 2021	February 14, 2021	(10.70)	(11.20)	(15.30)	(15.10)	(18.60)	(22.90)
February 12, 2021	February 15, 2021	(4.00)	(7.20)	(7.40)	(11.00)	(7.40)	(17.90)
February 12, 2021	February 16, 2021	4.40	2.50	0.30	(1.80)	(1.50)	(10.50)
February 16, 2021	February 17, 2021	6.30	7.70	4.10	4.80	(2.90)	(2.40)

1_/Weather Forecast is as of 7:00 a.m. business day prior to gas day

colder than forecast
warmer than forecast

Q. ARE THE IMPLICATIONS OF THIS DATA SIMILAR TO THOSE OF THE WEATHER DESK DATA?

A. Yes. More natural gas was required than would have been anticipated than indicated based on the weather forecasts.

Q. WOULD IT HAVE BEEN POSSIBLE TO RESPOND TO THESE VARIANCES BY PURCHASING MORE NATURAL GAS DURING THE THREE-DAY WEEKEND OR DURING INTRADAY PERIODS EACH DAY?

A. Based on industry practice, my own experience, and what was learned through RBN's widespread interviews in the market, not to any significant extent and it would have been unreasonable to rely on such purchases being possible. Because all available natural gas had been committed on Friday, February 12, there was effectively no market during the weekend. As for intraday purchases late in the day, for example in the evening when temperatures drop to extremely low levels, it is not feasible to secure transportation capacity. The final opportunity to change a nomination, the third intraday cycle, nominated at 7:00 p.m., is "no-bump." That is, the firm shipper may not increase its nomination if doing so would displace service to any other party on the pipeline, including interruptible shippers. Thus, if the pipeline is full, there is no way for new gas to be shipped that night. Sellers are well aware of this constraint, so they do not hold any gas back for possible late-day sales.

B. Loss of Supply in Texas and Oklahoma

Q. HOW IMPORTANT ARE TEXAS AND OKLAHOMA TO MINNESOTA'S NATURAL GAS SUPPLY?

A. Texas and Oklahoma are very important. Of the four major supply pipelines serving Minnesota, NNG is by far the dominant pipeline. For the first twelve days of February, NNG's total receipts from all sources, Texas, Oklahoma, Canada, and the Rockies, averaged 8.14 billion cubic feet per day ("Bcf/d"). Of that, 3.97 Bcf/d, or 49 percent, came from Texas and Oklahoma.

Q. WHAT IMPACT DID WINTER STORM URI HAVE ON THOSE FLOWS?

A. Total NNG receipts from Saturday, February 13, through Wednesday, February 17 averaged only 6.44 Bcf/d, a sudden drop of 1.7 Bcf/d or 21 percent, at the same time that the demand for natural gas and electricity was reaching levels well above forecasts across the midcontinent.

Q. HOW MUCH OF THE DECLINE WAS ATTRIBUTABLE TO TEXAS AND OKLAHOMA?

A. The decline in Texas and Oklahoma supplies was actually greater than the decline in total receipts. Between the twelve days ended February 12 and the five days ended February 17, Texas and Oklahoma combined receipts on NNG dropped by 1.97 Bcf/d, or 50 percent. NNG was able to pull from other sources to make up the 0.27 Bcf/d difference between the Texas/Oklahoma decline and the total system decline. Table 2, below, summarizes these quantities.

Table 2—NNG Receipts February 1 - 17

	Feb 1-12	Percent of Total	Feb 13-17	Percent of Total	Change	Percent
Total NNG Receipts, Bcf/d	8.14	100%	6.44	100%	(1.70)	-21%
Texas Receipts Bcf/d	3.57	44%	1.78	28%	(1.78)	-50%
Oklahoma Receipts Bcf/d	0.40	5%	0.19	3%	(0.22)	-54%
TX-OK Total Receipts Bcf/d	3.97	49%	1.97	31%	(2.00)	-50%

Q. PLEASE EXPLAIN THIS LARGE LOSS OF AVAILABLE GAS SUPPLY FROM TEXAS AND OKLAHOMA.

A. On September 23, 2021, the staffs of FERC and the North American Electric Reliability Corporation (NERC) presented to the FERC commissioners the preliminary findings of a report on Winter Storm Uri impacts on the electric grids, with a high degree of focus on natural gas.[8] Exhibit___(RGS-1), Schedule 5, Page 1 of 2 consists of two key charts from that report, tracking loss of production from three states including Texas and Oklahoma, first in absolute Bcf/d terms, and second in percentage terms for both wellhead production and processing-plant output. As can be seen, Texas suffered the most severe decline of the three states, approximately 12 Bcf/d. Two thirds of that decline was in the Permian Basin in West Texas, which is one of NNG's major supply sources.

Meanwhile, ever since the end of the Winter Storm Uri crisis, many proceedings, presentations to the Texas Senate, and expert symposia have been conducted throughout Texas. On behalf of RBN, in concert with the Energy Bar Association and the University of Texas, I helped organize and presented at a July symposium on the crisis. Exhibit___(RGS-1), Schedule 5, Page 2 of 2 is a Permian-specific analysis we performed for that effort and others, based on RBN's extensive and widely recognized expertise in that basin.

Q. PLEASE DESCRIBE SCHEDULE 5, PAGE 2 OF 2 AND WHAT IT INDICATES RELEVANT TO GAS SUPPLY AND PRICES.

A. As shown in the chart and explained below it, from the day before the onset of Winter Storm Uri, Friday, February 12, through 1:30 a.m. on Monday, February 15 wellhead, processing and pipeline freeze-offs caused a decline of 2.3 Bcf/d,

[8] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations, FERC Docket No AD21-28.

or 19.5 percent. That decline combined with loss of wind-turbine efficiency because of blade icing, loss of a unit at the South Texas nuclear plant, generation plant unavailability because of frozen lines and equipment, and frozen coal piles at coal-fired generating stations resulted in ERCOT declaring an emergency and instituting rolling blackouts. ERCOT did so at 1:30 a.m. Monday, but the blackout had an unpredicted impact—it turned off power to the vast bulk of wellhead operations, processing facilities, and pipelines moving gas from the Permian to market. As a result, the Permian output dropped by 2.9 Bcf/d, or 25 percent, from 1:30 a.m. to 9:00 a.m. Monday, the end of the Sunday Gas Day. Monday, output fell another 20 percent, and Tuesday, February 16, another 10 percent. At the end of that period, the Permian output had dropped by 8.7 Bcf/d, or 74.5 percent.

Q. WHAT WAS THE IMPACT OF THAT DROP IN PERMIAN OUTPUT?

A. That drop represented approximately 10 percent of all U.S. natural gas production from all sources, and thus was truly cataclysmic—it made the "rolling blackout" situation unrecoverable, leading to the well-known and deadly extended blackout, property damage, and water contamination in much of the state. Such a profound loss of natural gas supply from one of the largest fields in the nation was a primary driver of the unprecedented escalation in spot prices for natural gas. Every portion of the middle of the nation was affected by the shortage of supply and the consequent price run-up. The unluckiest regions, particularly Texas, parts of Oklahoma, and parts of Arkansas, suffered both loss of gas supply and tremendous price escalation, with Texas being the hardest hit by the deadly blackout.

Q. DID OTHER STATES DEPENDENT ON TEXAS GAS SUPPLY SUFFER SIMILAR IMPACTS?

A. Fortunately, they did not. In other states, such as Minnesota, emergency actions by the utilities – including procuring adequate supply, with a reserve margin – protected their customers against rapidly changing and unpredictable events. Therefore, they were able to maintain service to their customers, keeping homes warm and the power on. Having personally suffered through the Texas situation, it is clear that the utilities in states such as Minnesota made the correct decisions to prevent massive human-needs impacts.

C. Response by Market Participants, February 11-16

Q. HOW DID PIPELINES AND OTHER SERVICE PROVIDERS RESPOND TO THE SUDDEN POTENTIAL DISRUPTION OF SUPPLY IN THE FACE OF INCREASING DEMAND?

A. Both NNG and NiGas, upon whose ample storage the Minnesota utilities largely depend, declared "critical days" through all or most of the crisis. NNG issued its notices day by day, starting on Friday, February 12, effective on Saturday. It then issued five more identical notices for February 14, 15, 16, 17, and 18. These declarations essentially tightened all flow tolerances, leaving utilities with the risk of three-times-spot penalties if they varied from their scheduled quantities—quantities that began to be cut almost from the beginning of cold weather. These notices are reproduced in Exhibit___(RGS-1), Schedule 6, Pages 1 through 6. NiGas actually issued its critical-day notice prior to NNG's first notice, restricting storage activity for February 13 through 15. Additionally, the restricted and inflexible NNG transportation service frustrated the ability to use NiGas storage effectively to correct for fluctuations or inadequacies of flowing volumes to meet demand. The tightening of these delivery services sharply exacerbated the simple lack of commodity flowing supply.

Q. HOW DID VARIOUS MARKET PARTICIPANTS RESPOND TO SHORT-TERM WEATHER FORECASTS AND EVOLVING FACTS FROM FEBRUARY 11 FORWARD?

A. As of February 11, daily prices for February 12 remained relatively low, indicating that the quantities of spot gas buyers were buying continued to be reasonably accommodated by then-current gas supplies. Meanwhile, knowing that severe weather was continuing, and by then had been predicted to involve large areas of key supply states, LDCs, generators, and industrial consumers made their short-term plans for the weekend, which, as explained earlier, would actually span four days. These plans came to fruition as nominations were made on February 12 for the weekend. Pipeline nominations were due by 1:00 p.m. that day, but based on interviews with multiple purchasers in Minnesota, the common practice is to have supply committed and nominations tied down in the period from 7:00 a.m. to 10:00 a.m.. Further, utility contracts with gas suppliers often require utilities to "call" upon contracted for swing gas supply long before the 1:00 p.m. pipeline nomination deadline. It was during the 7:00 to 7:30 a.m. timeframe that supplier reactions to the impending weather event began to manifest themselves.

Q. WHAT WAS THE GENERAL RESPONSE FROM BUYERS IN TERMS OF THE VOLUMES SOUGHT FOR PURCHASE?

A. LDCs sought to secure enough supply to have a reserve margin against supply cuts, pipeline issues, etc., and in particular, to avoid very severe pipeline penalties for overrunning their scheduled quantities. On the largest pipeline, NNG, those penalties would be three times the daily spot price, approximately

$695 per MMBtu of overrun. These tight balancing tolerances and severe penalties were taken into account by the LDCs. Power generators also nominated high quantities, in that they expected all pipelines affected by the crisis to impose a requirement of even hourly flows, whereby a scheduled daily quantity must be taken in even hourly increments of 1/24th each hour, with no ability to move supply from one hour to the next. This restriction meant that power generators needed daily nominations and purchases based upon 24 times their peak hour, in order to comply with MISO dispatching. This move by generators to ensure reliability necessarily placed significant upward pressure on prices.

Q. COULD POWER GENERATORS HAVE NOMINATED ELEVATED LEVELS OF PIPELINE CAPACITY WHILE PURCHASING JUST ENOUGH NATURAL GAS TO FILL THEIR EXPECTED ACTUAL FLOWS DURING THE DAY, THUS PLACING LESS UPWARD PRESSURE ON PRICES?

A. No. In the nomination-to-scheduling process, the customer's nomination must be confirmed to the pipeline by the supplier involved—that is, if the customer nominates 1,000 units for the day, a supplier must confirm that the customer has purchased that amount, or the full nomination will not be scheduled by the pipeline. In the case of power generators, that would mean that their available hourly flow at 1/24 of their daily scheduled quantity would fall short of their peak hourly needs, limiting their ability to meet MISO nominations and potentially risking a loss of electric service.

Q. DID ELEVATED PURCHASES, INCLUDING A RESERVE MARGIN, BY LDCS HAVE THE SAME EFFECT AS THE POWER GENERATORS' PURCHASES OF NATURAL GAS BEYOND THEIR ACTUAL DAILY REQUIREMENTS?

A. Not in the same way. The LDC reserve margin purchases were specifically made as insurance against failures of supply, or failures of delivery during the extremely unpredictable severity of Winter Storm Uri, during a four-day weekend when new supply could not be obtained. Given the cuts in supply made during NNG's intraday cycles for the weekend because of supply that did not arrive, that insurance was an extremely prudent measure. As I explained in tracking the failure of Texas supply, it was not until ERCOT's blackout at 1:30 a.m. on Monday, February 15, over halfway through the four-day weekend, that the worst supply crisis struck, when LDCs were still relying on the purchases and pipeline nominations they made two and a half days earlier, that were cut as supplies went into *force majeure* and scheduled volumes were reduced. The reserve margins going into the weekend were very important and may have prevented severe failures in service.

D. Nature of Price Behavior

Q. SHOULD/COULD BUYERS HAVE ANTICIPATED THE EXTREMELY ELEVATED PRICE LEVELS COMING INTO THE MONTH OF FEBRUARY?

A. Not in my opinion. For many years, since the advent of abundant production from the Rockies combining with Canadian gas and gas from traditional areas in Texas and Oklahoma, the upper Midwest has been blessed with some of the most reasonable, stable prices in the nation. Then, the advent of shale technology in the early 2000s, followed by its massive application in the very mature Permian Basin, flooded the midcontinent with ample supply from multiple directions (which also relieved many pipeline constraints by multi-directional feed). The result has been extremely stable market prices for at least the last ten years.

Q. HAVE YOU QUANTIFIED HOW STABLE THE MARKET PRICES HAVE BEEN AND HOW THEY COMPARE WITH THIS YEAR'S EXPERIENCE?

A. Yes. Exhibit___(RGS-1), Schedule 7 examines the last ten years of history of prices for the key market hubs accessed by the four main pipelines serving Minnesota. On Schedule 7, Page 1 of 2, the ten years from February 1, 2011 to February 11, 2021 is charted, showing extremely stable prices in the $2.00 to $4.00 range throughout the ten years, with the exception of only a couple of sharp price increases and those increases that did not approach the levels reached during the February Event. One other important observation is that in February 2011 Texas experienced a massive freeze and rolling blackout event approaching the severity of this year's February event, including loss of power to gas supply infrastructure. However, as can be seen, there was no price spike in February 2011. This indicates that the confluence of events this year created a situation never seen before and that could not have been anticipated.

The second chart on Schedule 7, Page 1 of 2, extends the data through the 2021 crisis. As is apparent, the price spike experienced this year was vastly higher than any experience during the last ten years.

Q. HAVE YOU QUANTIFIED OTHER ASPECTS OF PAST PRICE BEHAVIOR?

A. Yes. Schedule 7, Sheet 2 of 2 examines the ten-year price behavior prior to Winter Storm Uri in terms of maximum prices experienced at each market hub, and maximum duration of prices higher than $5.00 and higher than $10.00, performing each review for the last ten years and the last five years. It is noteworthy that, focusing on Demarc, there have been no days of a price above $10.00 in five years and only four days above $5.00, with the longest contiguous duration being two days. In ten years, Demarc has seen 50 days above $5.00, and only five days above $10.00, with the longest duration being two days.

Q. WHAT DOES THIS ANALYSIS DEMONSTRATE?

A. It demonstrates that it was reasonable to assume that abundant natural gas supplies would keep any price increases modest, even in the face of severe cold in the upper Midwest. Over the ten-year period, there had been many very severe weather periods for Minnesota, and even the most severe price spikes had been short-lived and at levels a fraction of what took place during Winter Storm Uri. Coupled with weather forecasts that, as of the end of January, indicated cold weather in Minnesota, but relatively normal weather in Texas and Oklahoma production areas, the utilities could expect, based on many years' experience, to go through a normal cold-weather protocol, bringing in gas inclusive of a reserve margin from daily market purchases.

E. Minnesota Vs. Texas

Q. HOW DID MINNESOTA'S EXPERIENCE COMPARE WITH THAT OF TEXAS?

A. The first and most obvious difference is that Minnesota utilities maintained service, both gas and electric, in the face of a severe winter storm that for the first time in many years had a major impact on the availability of Texas and Oklahoma natural gas supplies. Texas did not have similar success. ERCOT had to institute a massive and unpredictable blackout to avoid damage to the grid that could have taken weeks to correct. Moreover, the vast majority of the power generation in ERCOT is natural gas-fired generation owned by independent power producers, who drove natural gas prices up in a quest to capture extremely high ceiling prices for power in ERCOT--$9,000 per Megawatt-hour for four days.

Q. WHERE THERE OTHER OPERATIONAL DIFFERENCES?

A. Yes. Texas gas buyers had a particular problem, in that the disastrous drop in production in the Permian Basin and other Texas producing areas represented all the natural gas reasonably available to the market. The sheer size of the Texas producing areas, spanning multiple parts of the state and multiple climate zones, coupled with the dominance of those supplies in terms of gas production, had left Texas with little supply diversity from outside the state. In contrast, Minnesota receives significant supply from the south and southwest, but also receives supplies from the Rockies, California, and even from the Northeastern U.S., through the Rockies Express pipeline, moderating the impact in comparison to Texas, where prices reached approximately $400 per MMBtu by February 17, or Oklahoma, where they reached $1,000. Minnesota also benefitted from being served with dry pipeline gas that had little danger of local freeze-offs, whereas in Texas, the freeze-offs happened both at the wellhead and in the processing and pipeline infrastructure, since so much gas was produced close to the market that it was relatively wet. Then Texas experienced the cascading impact of loss of supply causing a blackout that cut power to critical gas facilities, thus further cutting gas supply for power generation, creating a dangerous interactive cycle of collapse. Nothing like that happened in Minnesota, although of course, Minnesota did suffer in terms of price from the chaos in the Texas-Oklahoma supply area. The end result was that adaptation to very cold weather, good planning, and prudent operation caused Minnesota to fare much better than did Texas.

V. CONCLUSION

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM YOUR TESTIMONY?

A. The general industry and situation overview I provided, focusing on the elements most relevant to the experience of the Joint Gas Utilities, demonstrates that the group faced an unprecedented challenge. Weather during a four-day gas market weekend turned out to be consistently colder than had been predicted in late January and more widespread than had been predicted until a handful of days before the February Event. Additionally, in a development not seen to the same degree in at least the last decade, there was a substantial weather-driven failure of supply from major Texas and Oklahoma supply areas upon which the Minnesota market places significant reliance. Simply put, demand was up and supply was down, resulting in a sellers' market price runup of historic proportions and creating substantial uncertainty about the reliability of flowing supplies over a holiday weekend when business would be very difficult if not impossible to transact, to bring new supplies on line. Maintaining service along with an adequate reserve margin to deal with contingencies in an unknown, crisis situation (and thus keeping their customers warm and the electric power on) was difficult and made more difficult by the extremely high prices. Doing so required all available resources and the full experience and expertise of utility operators. The price tag for doing this was high, but it was essential that the maintenance of reliable service had to be the paramount concern. The success achieved across the state, as compared with the massive failures experienced in Texas attests to the operational planning and execution of the utilities.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

QUALIFICATIONS AND EXPERIENCE OF RICHARD G. SMEAD

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science in Mechanical Engineering from the University of Maryland and a Juris Doctor degree from George Washington University. I have 34 years of experience in the natural gas industry, 10 years working for the local distribution system serving the Washington, D.C. metropolitan area, and 24 years working for major pipeline companies (16 of which were in senior management). I also have 17 years of experience in consulting in all regulatory, commercial, and strategic aspects of the natural gas industry.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No.

Q. HAVE YOU TESTIFIED IN FRONT OF ANY OTHER REGULATORY BODIES OR COURTS?

A. Yes. Exhibit___(RGS-1), Schedule 2 is a complete list of my past testimony, listing fifty-eight proceedings in twenty-four jurisdictions.

Q. PLEASE DESCRIBE IN DETAIL YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS AS AN EXPERT.

A. From 1970 to 1980, I was employed by Washington Gas Light Company ("Washington Gas"). I held a variety of positions including engineering and management positions in distribution, gas supply, utilization research, corporate planning, and rates, in particular Federal regulatory affairs involving Washington

Gas's service from interstate pipelines regulated by the Federal Energy Regulatory Commission ("FERC"). In 1980, I joined Tennessee Gas Transmission Company, later the Tenneco Gas Group, as Manager of Rates. I ultimately progressed to Director of Rates for the multiple interstate and intrastate pipelines owned wholly or in part by Tenneco Inc. (including Tennessee Gas Pipeline Company, then the largest pipeline system in the United States), with responsibility for all FERC matters involving those pipelines. In 1988, I joined Colorado Interstate Gas Company ("CIG"), a subsidiary of The Coastal Corporation ("Coastal"), as Vice President, Regulatory Affairs, with overall management responsibility for all of CIG's FERC matters, as well as those of its affiliate Wyoming Interstate Company, Ltd. In 1995, I moved up to Senior Vice President, Regulatory and Tax, for CIG, and in 1999 became Senior Vice President, Regulatory Affairs for Coastal's larger pipeline system, ANR Pipeline Company ("ANR"), in addition to my CIG duties. In 2001, upon the merger of Coastal with the El Paso Corporation ("El Paso"), I became Vice President, Regulatory Policy, for El Paso's extensive pipeline group, the largest natural gas pipeline network in North America at the time. In 2004, I left El Paso and joined Navigant Consulting Inc. ("Navigant") as a Director in Navigant's energy practice, with primary responsibilities for management and regulatory consulting services in the upstream and midstream natural gas business. Then, in October 2013, I left Navigant to join RBN in my current position.

Q. IN ADDITION TO YOUR EXECUTIVE AND CONSULTANT WORK, HAVE YOU BEEN ACTIVE IN INDUSTRY TRADE AND PROFESSIONAL ASSOCIATIONS, AND HAVE YOU PUBLISHED AND SPOKEN OR TAUGHT IN AREAS RELATED TO THE ENERGY INDUSTRY?

A. Yes. When in the natural gas industry, I was active in the Interstate Natural Gas Association ("INGAA") and the American Gas Association ("AGA"), chairing multiple committees and task forces for each. I have also been active in the North American Energy Standards Board ("NAESB") and its predecessor organization, the Gas Industry Standards Board since inception of the organization, having been on the board of directors and a member representative at various times. I am active in the Energy Bar Association ("EBA"), the national association of energy regulatory attorneys, currently serving on the board of directors and as treasurer. As for speaking, teaching, and publishing, I have been a frequent author and speaker on the subject of natural gas. For decades, I have taught natural gas overview and rate courses for the AGA, for the Center for Public Utilities, for the University of Houston, the University of Texas, and Georgetown University. I currently am the natural gas columnist for *Climate & Energy*, a monthly journal produced by Wiley Publications, a position I have held for over 30 years.

Q. ASIDE FROM YOUR CAREER WITH PIPELINES, AS A CONSULTANT HAVE YOU BEEN INSTRUMENTAL IN THE CURRENT EVOLUTION OF THE NATURAL GAS INDUSTRY?

A. Yes. Most significantly, I have been extremely involved in the paradigm shift from perceptions of natural gas shortages to the current understanding of natural gas abundance. In 2008, I was co-author, project manager, and public representative of Navigant's comprehensive study of North American natural gas supply for the American Clean Skies Foundation ("ACSF"). This study was the first comprehensive quantification of the extent of recoverable shale gas in the U.S. and led, in turn, to the bulk of my practice for the past twelve years being focused on natural gas abundance and its implications. Working for clients such as ACSF, the American Petroleum Institute ("API"), America's Natural Gas Alliance ("ANGA"), and various producers and consumers of natural gas. A major area of focus of that work has been to help facilitate the use of natural gas for power generation, helping regulators understand the dynamics and in particular helping deal with issues of pipeline development and economics, to allow the nation's natural gas abundance to reach end-users. I have also worked with Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), sometimes through API, and from 2015 through 2019 as an advisor to the Midcontinent Independent System Operator ("MISO"). The MISO work involved helping understand and manage a major shift from coal to gas, both in anticipation of regulatory requirements and more recently simply because of the favorable economics of natural gas.

Q. DO YOU HAVE EXPERIENCE IN THE LDC INDUSTRY THAT IS RELEVANT TO THIS PROCEEDING?

A. Yes. During my ten years at Washington Gas, four were spent in the Gas Supply Department, interacting directly with the gas control and planning process, and three were spent in the Corporate Planning Department, helping orchestrate Washington Gas's return to business growth following new-customer freezes during the natural gas shortages of the late 1960s and 1970s. Much more recently, during my tenure as a senior officer at CIG, I was directly involved in the daily and monthly interactions with Public Service Company of Colorado ("Public Service") and Colorado Springs Utilities ("CSU") regarding the various services that CIG provided as their primary supplier and how it interacted with their load profiles. I have also had a long involvement with the American Gas Association, which represents the LDC industry, have been a member, have been chairman of the different committees identified above, and have consulted in several work products for the association.

Q. DO YOU HAVE EXPERIENCE IN THE POWER GENERATION USE NATURAL GAS AND ITS INTERACTION WITH PIPELINES AND SUPPLIERS?

A. Yes. Since 2001, I have been actively involved in the efforts to improve gas-electric harmonization, primarily on behalf of the gas pipeline industry. Since 2005, I have been a member of each NAESB task force charged with developing standards and identifying policy issues in the service of power generation by natural gas companies, having co-chaired the original task force in 2005. A new effort has just been undertaken, and I was named to the committee pursing it. In my various roles exploring the implications of natural gas abundance since 2008, I frequently met with utilities, state regulators, and regional transmission organizations or independent system operators, to explore gas-electric issues and to support the use of natural gas for power generation. From 2016 through 2020, As noted, I also was a consulting advisor for MISO, the geographically largest ISO in North America, regarding issues surrounding MISO's members' increasing use of natural gas.

Q. HAS ANY OF YOUR WORK INVOLVED UTILITY PRACTICES AND DECISIONS IN THE FACE OF THE EXTREME WEATHER EVENT?

A. Yes. Since the events of Winter Storm Uri, I am participating as an expert witness for several entities as to their experiences during the crisis. Further, on behalf of the EBA, in July of this year, I helped organize and spoke at a major symposium at the University of Texas in Austin, regarding the Winter Storm Uri blackout in ERCOT, the organized power market in Texas. I concentrated on the failure of natural gas production in Texas during Winter Storm Uri, the reasons for it and potential remedies. My work there was grounded in RBN's core competency in the behavior of U.S. and regional natural gas production and the interaction with infrastructure, and was indicative of the experience of multiple other producing regions.

PRIOR TESTIMONY OF
RICHARD G. SMEAD

Regulatory Testimony (All FERC, unless otherwise noted)

Cases Which Went to Hearing

Company	Docket No.	Issue
As a Pipeline Executive, 1980-2000		
Tennessee Gas Pipeline Company	RP 80-97, 81-54	Depreciation
Tennessee Gas Pipeline Company	RP 81-54, 82-12	Negative Salvage
Midwestern Gas Transmission Co.	RP 81-17, et al.	Depreciation
Midwestern Gas Transmission Co.	RP 86-33	Cost Allocation and Rate Design, Min. Bill
Southern Natural Gas Co. (OBO TGP)	RP 83-58	Cost Allocation
Southern Natural Gas Co. (OBO TGP)	RP 86-63, 86-116	Minimum Bill
Kern River Gas Transmission Co.	CP 85-552	Rate Policy, all issues
Wyoming Interstate Co., Ltd. (OBO TGP)	RP 85-39, Ph. I	Rate Design
Ozark Gas Transmission Co. (OBO TGP)	IN 86-6	Refund Disposition
Colorado Interstate Gas Company	RP 90-69	Rate Policy, all issues
Wyoming Interstate Co., Ltd.	RP 85-39, Ph. II	Rate Policy, all issues
Wyoming Interstate Company Ltd.	RP 99-381	Rate Policy, depreciation, Rate of Return
Guardian Pipeline (OBO ANR)	Wisconsin PSC 6650-CG-194	Cost of Guardian alternative to ANR Service
As a Consultant, 2010-Present		
El Paso Natural Gas Company	RP10-1398	Pipeline right to fair opportunity of recovery
TransCanada Pipe Lines Ltd (OBO Alberta DOE)	RH 3-2011 (NEB of Canada)	Cost allocation mitigation for throughput loss, opposition to Alberta System Extension
Washington Gas Light	PUE-2013-00063 (SCC of Virginia)	State jurisdiction over release of Transco storage capacity.
BP Energy	IN13-15	No NGA jurisdiction over Texas transactions
Public Service Company of Oklahoma	PUD201500208 OCC of Oklahoma	Natural Gas Supply and Price Stability
Public Service Company of Oklahoma	PUD201700267 Oklahoma CC	Natural Gas Price estimates
Southwestern Electric Power Company	47461 PUC of Texas	Natural Gas Price estimates
Southwestern Electric Power Company	17-038-U Arkansas PSC	Natural Gas Price estimates
Virginia Natural Gas	Va. State Corporation Commission, PUR-2018-00203	

Filed Testimony, No Hearing to Date

Company	Docket No.	Issue
As a Pipeline Executive, 1984 – 2001		
Tennessee Gas Pipeline Company	RP 84-17	Rate Policy, all issues
East Tennessee Natural Gas Co.	RP 85-149	Rate Policy, all issues
Niagara Interstate Pipeline System	CP 83-170	Rate Policy, all issues
Midwestern Gas Transmission Co.	RP 86-33	Rate Policy, all issues
TransCanada Pipe Lines Ltd. (OBO TGP)	RH 3-86 NEB of Canada)	Rate Design
Columbia Gas et. al. (OBO TGP)	RP 86-168, et. al.	Cost Allocation and Rate Design
Tennessee Gas Pipeline Company	RP 88-228	Seasonal Rates
Questar Pipeline Company (OBO CIG)	RP 91-140	Cost Allocation
Colorado Interstate Gas Company	RP 93-99	Rate Policy, all issues
Wyoming Interstate Company Ltd.	RP 94-267	Rate Policy, all issues
Public Service Company of Colorado	CPUC 34814, 34815 (Colo. PUC)	Order 636, GCA recovery
Colorado Interstate Gas Company	RP 96-190	Rate Policy, all issues
Wyoming Interstate Company Ltd.	RP 97-375	Rate Policy, all issues
Colorado Interstate Gas Company	RP 01-350	Overall policy, depreciation, rate of return
As a Consultant, 2007-Present		
Arkansas Oklahoma Gas Company	07-026-U (AR PUC)	Rate of return
Columbia Gulf Transmission Company	RP 11-1435	Business Risk, tariff issues
Venice Gathering System LLC	RP15-1237, 16-975	All issues, ROR, Depreciation
Public Service Company of Oklahoma (OBO Chesapeake)	PUD201200054 Oklahoma CC	Natural Gas Supply and Price Stability
Vectren South	IURCC 45052 Indiana	Support for new NGCC, adverse coal industry waived cross
Consumers Energy (OBO Midland Cogen Venture)	MI PSC U-18010	Challenge to rate increase and hourly restrictions, case withdrawn after filing of testimony
Kinetica Deepwater Express LLC	RP19-1634	Rate Policy and Design, all issues
Northern Natural Gas Company	RP19-1953 *et al.*	Pipeline capacity and behavior out of Permian Basin
Oklahoma Gas & Electric	Cause No. PUD 202000069 Oklahoma CC	Justification of pipeline for Muskogee 4 &5
Oklahoma Gas & Electric	Cause No. PUD202100072 Oklahoma CC	Review of gas purchase Practices during WS Uri
Kinetica Energy Express LLC	RP21-780	Rate Policy and Design, all issues
Public Service Company of Colorado	21A-0192EG (Colo. PUC)	Rebuttal in Feb. 2021 gas purchase review

Tax Commissions

Company	Docket No.	Issue
As a Pipeline Executive, 1996 – 2004		
Colorado Interstate Gas Company Wyoming Interstate Company, Ltd.	Wyoming, Kansas Oklahoma, Colorado, Utah	Multiple property tax appeals 1996 - 2001 At least 10 depositions and hearings
Tennessee Gas Pipeline Co., ANR Pipeline	Ohio Tax Commission Case No. 0401223	Discriminatory assessment ratios Deposed
As a Consultant, 2004 – Present		
Appeal of ANR Pipeline Co.	Louisiana Tax Comm. Docket 06-22001-001	Effect of Regulation on valuation Testimony, no deposition

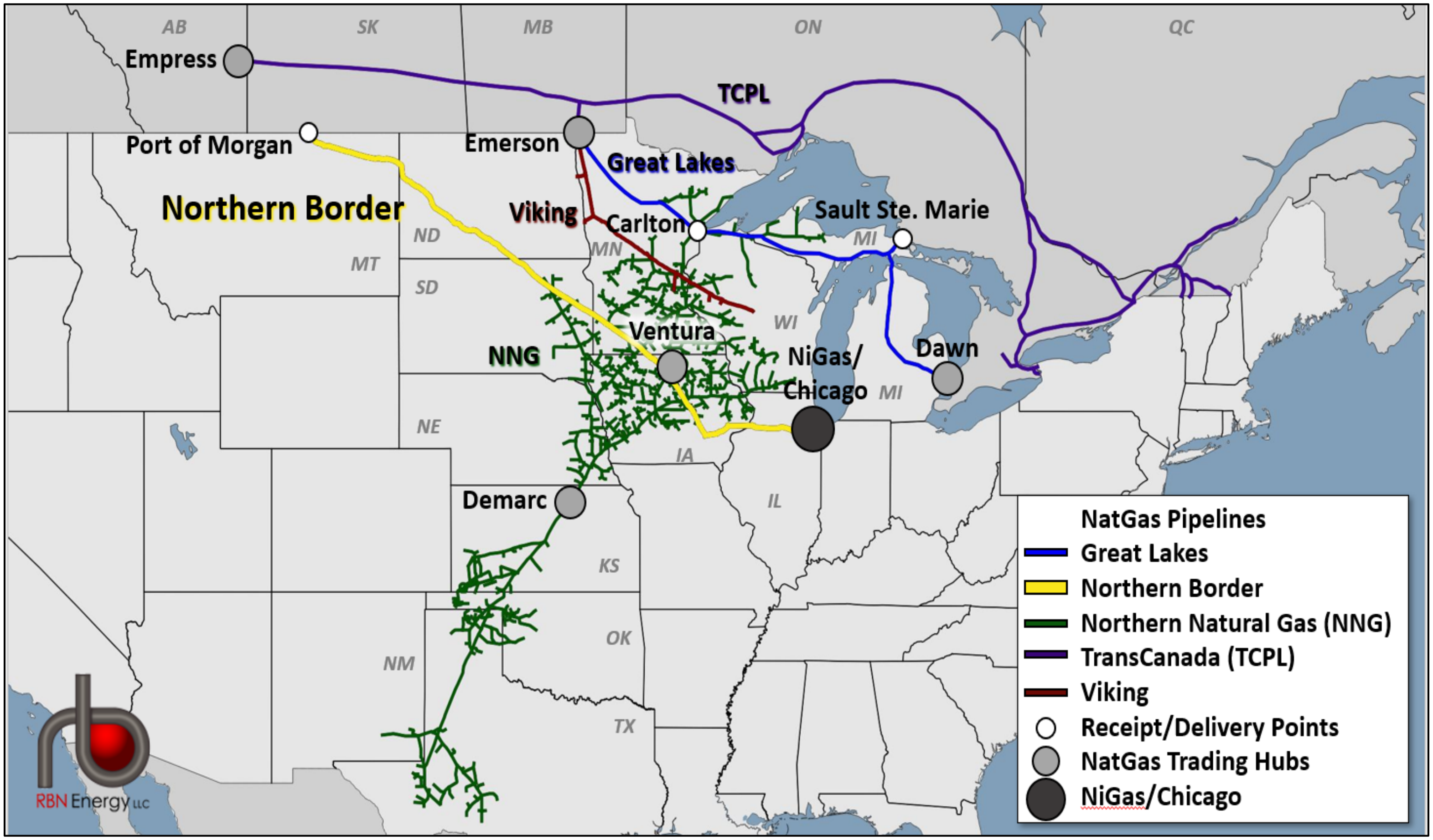
District Court

North Coast Transmission v. KNG Energy	Cuyahoga County Common Pleas Court, Case No. 04CV542460	Gas Balance Issues (Expert report only)
Tennessee Gas Pipeline Co., ANR Pipeline	Louisiana District Court 2005	Discriminatory assessment ratios
Peoples Gas Light & Coke v. Harrison CAD	Texas 71st District Court Cause 05-381	Ownership of storage gas for AVT purposes
Great Lakes Gas Transmission v. Essar Steel *et al.*	US District Court District of Minnesota Civil No. 09-CV-3037	Breach of contract, mitigation (expert report, deposition only--won summary judgment)
Columbia Gulf Transmission v. Louisiana	LA District Court	Application of LA Franchise Tax, measurement of revenue (deposed)
Houston Pipeline Company v. Harris County	Harris County District Court	Bammel Storage in interstate commerce (Expert report only)
LeaPartners LP v. New Mexico Taxation and Revenue Department	New Mexico, County of Santa Fe, First Judicial District, Case No. D-101-2011-03726 et al.	Proper cost for valuation pursuant to special statute for pipelines and gathering
Rainbow Gas Marketing Corporation v. American Midstream (Alabama Intrastate), LLC	District Court of Harris Harris County, Texas, 17th Judicial District	Breach of contract, interaction of interstate tariff and practices with connected intrastate agreement reliant upon interstate

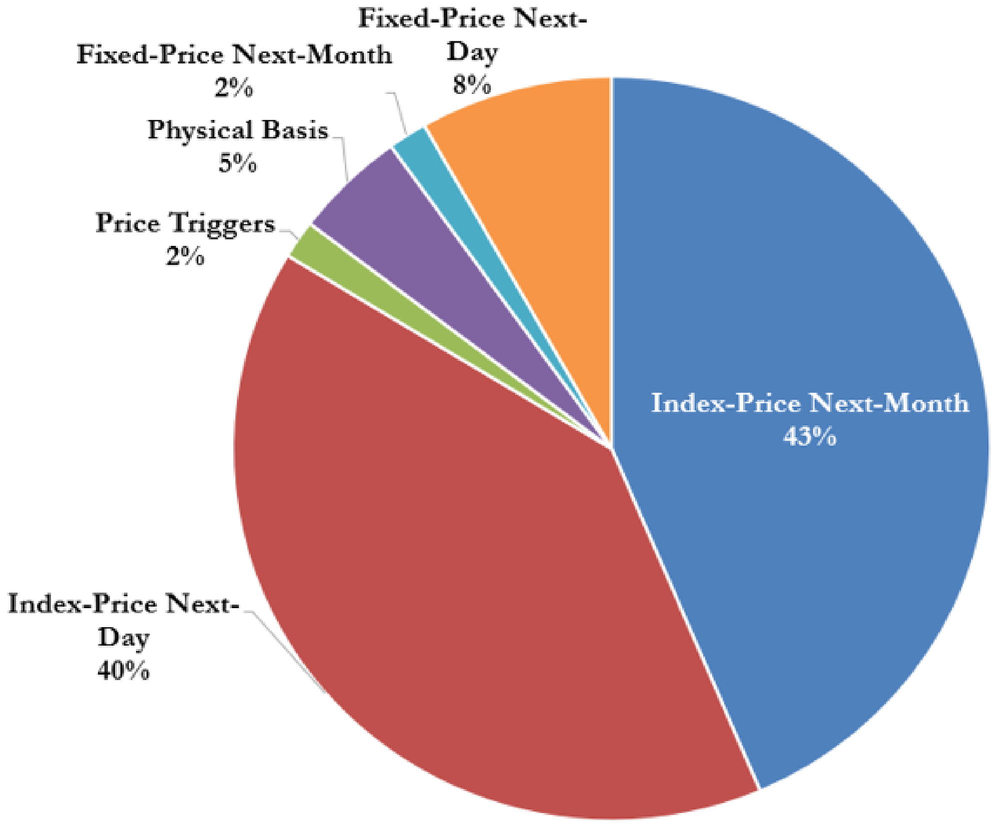
Other

Enbridge Gas Distribution	Ontario Energy Board Case EB-2005-0551	Market-power Issues re forbearance from price regulation of non-core storage

Map of Relevant Natural Gas Pipelines and Trading Hubs



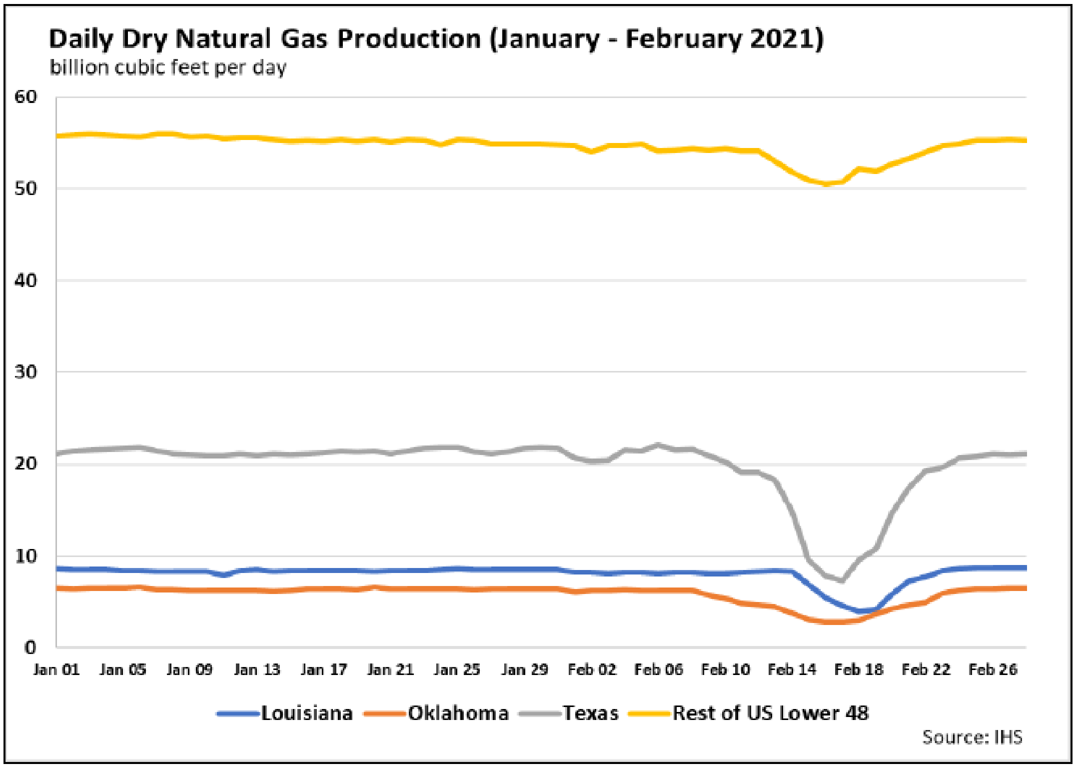
Breakdown of Commodity Deals, 2020

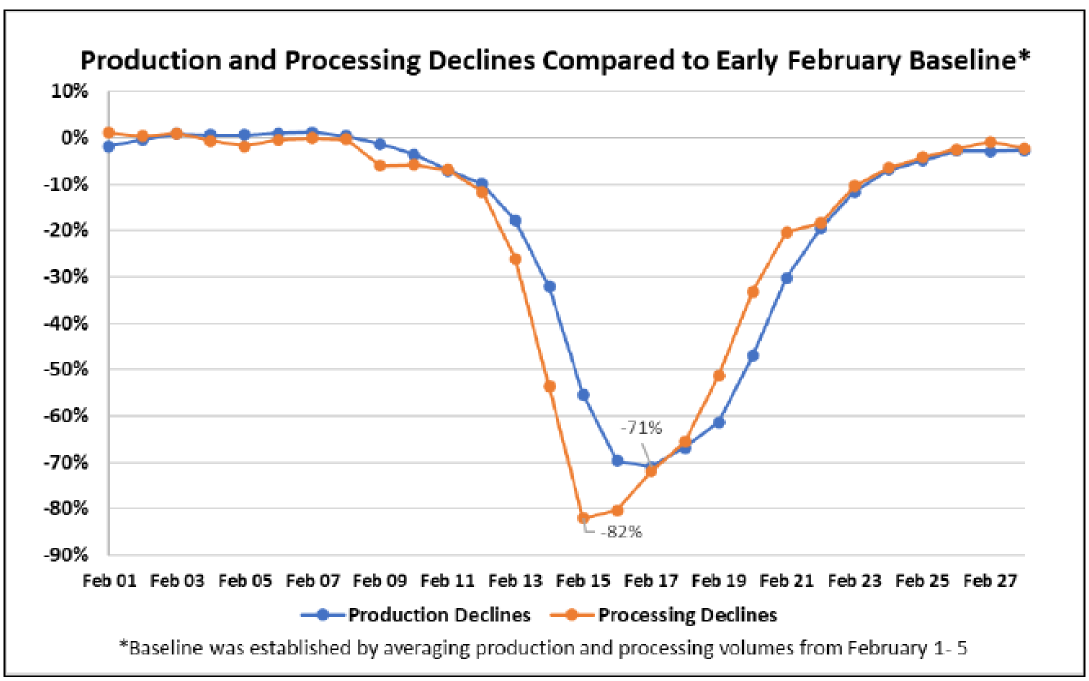


- Spot Day Gas: Next-Day Delivery
  - Fixed or Index Price for a single day delivery of gas
  - Delivery at a hub or point on a transport contract
  - ICE, IM, phone
- Spot Monthly: Bid Week
  - Fixed or Index Price for ratable next month delivery of gas
  - Delivery at a hub or point on a transport contract
  - ICE, IM, phone
- Other Pricing Mechanisms
  - Physical basis
  - Price triggers and physical options

Charts of Overall and Relevant Loss of Supply

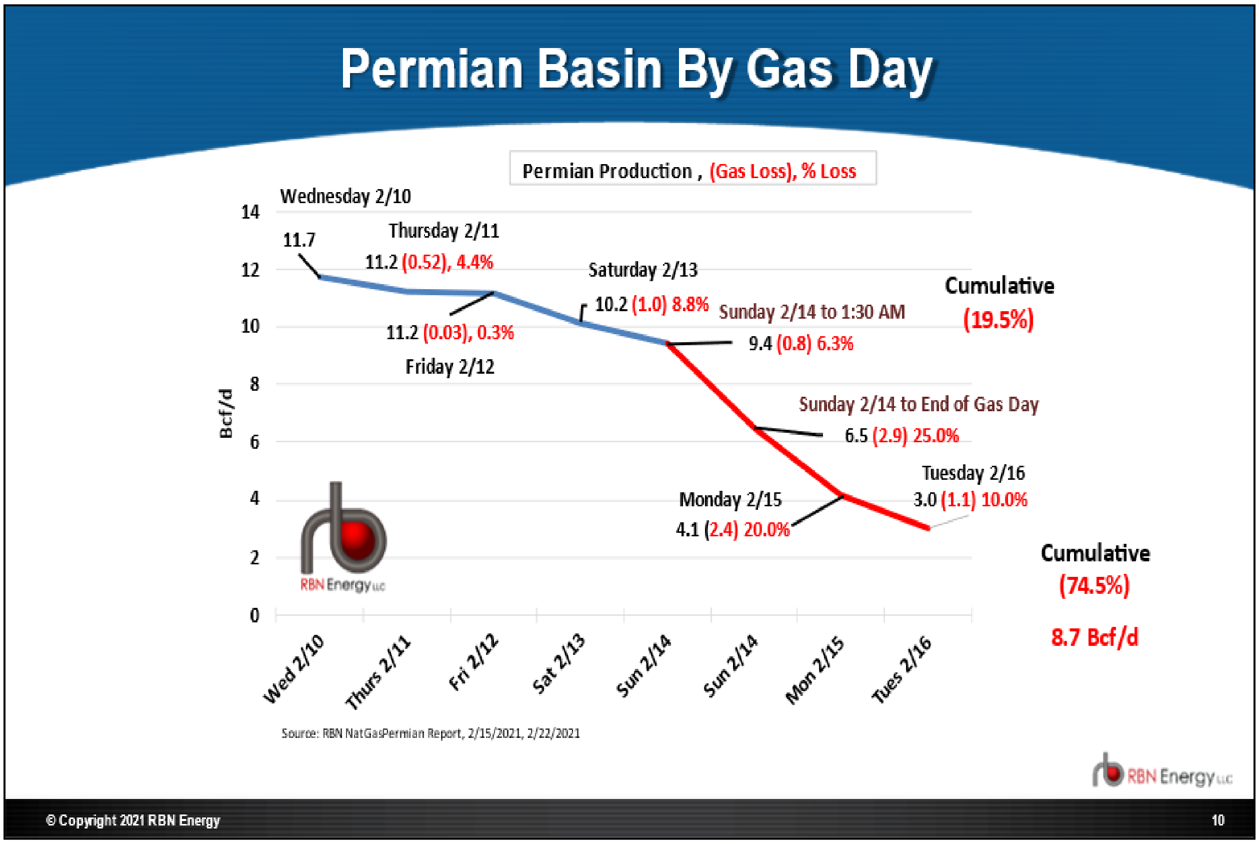
Excerpts from FERC-NERC September 23 Report





Charts of Overall and Relevant Loss of Supply

Permian Basin Day by Day Experience



From normal flow of 11.7 Bcf/d on Wednesday, February 10, flow dropped 4.4% to 11.2 Bcd/d on Thursday, February 11, then was almost flat on flat on Friday, February 12. On Saturday, there was another 8.8% decline to 10.2 Bcf/d, then from 9:00 AM Sunday to 1:30 AM Monday (still within the Sunday Gas Day), a further 6.3% decline to 9.4 Bcf/d accumulated to a total loss of supply of 19.5%, all primarily caused by freeze-offs. This combined with lost wind capacity, a nuclear outage, frozen coal piles, and frozen power generators, to require rolling blackouts.

Thus, at 1:30 AM Monday, the power went out to virtually all of ERCOT, including natural gas wells, processing plants, and pipelines. As a result, in the last 7.5 hours of the Sunday Gas Day, another 25.0%, 2.9 Bcf/d, was lost. Another 20% on Monday and 10% on Tuesday brought total production loss to 74.5%, 8.7 Bcf/d. Only 3.0 Bcfd remained flowing, a loss in one basin of almost 10% of all U.S. production. This rendered the Texas blackout unrecoverable and reduced the northbound supply (including on NNG) to a negative number.

NNG and NiGas Critial Notices for February 13-18

NNG Critical Notices for February 13 – 18
Reformatted for Page Fit
(Source: NNG Electronic Bulletin Board)

Notice Type	Notice Note
Operational Alert/Critical Day **Notice ID** 58494 **Supersede Parent Id** **Notice Subject** CRITICAL DAY FOR GAS DAY FEBRUARY 13, 2021 – ENTIRE SYSTEM **Actual Post Date Time** 02/12/2021 10:10 AM **Effective Post Date Time** 02/13/2021 9:00 AM **Termination Date Time** 02/14/2021 8:59 AM **Critical Flag** Y	Due to the severe weather conditions experienced in Northern's Market and Field Areas, the impact of well-head freeze offs in Northern's Field Area and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Saturday, February 13, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website. Northern's system weighted average wind-adjusted temperature is forecast to be -8 degrees for Saturday, February 13, 2021, and is forecast well below normal through the weekend. Northern's normal system weighted temperature is 19 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. As of 9:45 a.m. Friday, February 12, 2021, for Gas Day Saturday, February 13, 2021, Demarcation and Ventura have traded at or above $250.00 Dth. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantities. Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity. Refer to Tariff Sheet No. 291 for information related to Critical Day provisions. Please continue to monitor Northern's website for updates. If you have any questions regarding this notice, please contact your marketing or customer service representative. DDVC penalties are applicable to the bumped shipper's quantity.

NNG and NiGas Critial Notices for February 13-18

	Notice Note
Notice Type Operational Alert/Critical Day **Notice ID** 58527 **Supersede Parent Id** **Notice Subject** CRITICAL DAY FOR GAS DAY FEBRUARY 14, 2021 – ENTIRE SYSTEM **Actual Post Date Time** 02/13/2021 8:40 AM **Effective Post Date Time** 02/14/2021 9:00 AM **Termination Date Time** 02/15/2021 8:59 AM **Critical Flag** Y	Due to the severe weather conditions experienced in Northern's Market and Field Areas and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Sunday, February 14, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website. Northern's system weighted average wind-adjusted temperature is forecast to be -16 degrees for Sunday, February 14, 2021, and is forecast well below normal through the weekend. Northern's normal system weighted temperature is 19 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. For the weekend trading block that extends from Gas Day Saturday, February 13 through Tuesday, February 16, 2021, the average Northern Demarc and Northern Ventura prices were $231.67/Dth and $154.905/Dth, respectively. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantties. Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity. Refer to Tariff Sheet No. 291 for information related to Critical Day provisions. Please continue to monitor Northern's website for updates. If you have any questions regarding this notice, please contact your marketing or customer service representative. DDVC penalties are applicable to the bumped shipper's quantity.

NNG and NiGas Critial Notices for February 13-18

Notice Type Operational Alert/Critical Day **Notice ID** 58558 **Supersede Parent Id** **Notice Subject** CRITICAL DAY FOR GAS DAY FEBRUARY 15 2021 – ENTIRE SYSTE **Actual Post Date Time** 02/14/2021 8:30 AM **Effective Post Date Time** 2/152021 9:00:00 AM **Termination Date Time** 2/162021 8:59:00 AM **Critical Flag** Y	**Notice Note** Due to the severe weather conditions experienced in Northern's Market and Field Areas and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Monday, February 15, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website Northern's system-weighted average wind-adjusted temperature is forecast to be -10 degrees for Monday, February 15, 2021, and is forecast well below normal through the weekend. Northern's normal system-weighted temperature is 20 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. For the weekend trading block that extends from Gas Day Saturday, February 13 through Tuesday, February 16, 2021, the average Northern Demarc and Northern Ventura prices were $231.67/Dth and $154.905/Dth, respectively. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantities. Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity. Refer to Tariff Sheet No. 291 for information related to Critical Day provisions. Please continue to monitor Northern's website for updates. If you have any questions regarding this notice, please contact your marketing or customer service representative. DDVC penalties are applicable to the bumped shipper's quantity.

NNG and NiGas Critial Notices for February 13-18

	Notice Note
Notice Type Operational Alert/Critical Day **Notice ID** 58623 **Supersede Parent Id** **Notice Subject** CRITICAL DAY FOR GAS DAY FEBRUARY 16, 2021 – ENTIRE SYSTEM **Actual Post Date Time** 02/15/2021 8:37 AM **Effective Post Date Time** 2/162021 9:00:00 AM **Termination Date Time** 02/16/2021 8:59 AM **Critical Flag** Y	Due to the severe weather conditions experienced in Northern's Market and Field Areas, the impact of well-head freeze offs in Northern's Field Area and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Tuesday, February 16, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website Northern's system weighted average wind-adjusted temperature is forecast to be -1 degrees for Tuesday, February 16, 2021, and is forecast well below normal through the weekend. Northern's normal system weighted temperature is 21 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. For the weekend trading block that extends from Gas Day Saturday, February 13 through Tuesday, February 16, 2021, the average Northern Demarc and Northern Ventura prices were $231.67/Dth and $154.905/Dth, respectively. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantities. Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity. Refer to Tariff Sheet No. 291 for information related to Critical Day provisions. Please continue to monitor Northern's website for updates. If you have any questions regarding this notice, please contact your marketing or customer service representative. DDVC penalties are applicable to the bumped shipper's quantity.

NNG and NiGas Critial Notices for February 13-18

Notice Type Operational Alert/Critical Day **Notice ID** 58766 **Supersede Parent Id** **Notice Subject** CRITICAL DAY FOR GAS DAY FEBRUARY 17, 2021 – ENTIRE SYSTEM **Actual Post Date Time** 02/16/2021 9:25 AM **Effective Post Date Time** 2/172021 9:00:00 AM **Termination Date Time** 02/18/2021 8:59 AM **Critical Flag** Y	**Notice Note** Due to the severe weather conditons experienced in Northern's Market and Field Areas, the impact of well-head freeze offs in Northern's Field Area and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Wednesday, February 17, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website. Northern's system-weighted average wind-adjusted temperature is forecast to be 6 degrees for Wednesday, February 17, 2021, and is forecast well below normal through the week. Northern's normal system-weighted temperature is 21 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. As of 9 a.m. Tuesday, February 16, 2021, for Gas Day Wednesday, February 17, 2021, natural gas at Ventura has traded at or above $475/Dth. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveres to be above scheduled quantities. Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity. Refer to Tariff Sheet No. 291 for information related to Critical Day provisions. Please continue to monitor Northern's website for updates. If you have any questions regarding this notice, please contact your marketing or customer service representative. DDVC penalties are applicable to the bumped shipper's quantity.

NNG and NiGas Critial Notices for February 13-18

	Notice Note
Notice Type Operational Alert/Critical Day **Notice ID** 58900 **Supersede Parent Id** **Notice Subject** CRITICAL DAY FOR GAS DAY FEBRUARY 18, 2021 – ENTIRE SYSTEM **Actual Post Date Time** 02/17/2021 10:15 AM **Effective Post Date Time** 2/182021 9:00:00 AM **Termination Date Time** 02/19/2021 8:59 AM **Critical Flag** Y	Due to the severe weather conditions experienced in Northern's Market and Field Areas, underperformance of receipt points in Northern's Field Area and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Thursday, February 18, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website. Northern's system-weighted average wind-adjusted temperature is forecast to be 7 degrees for Thursday, February 18, 2021, and is forecast well below normal through the week. Northern's normal system-weighted temperature is 21 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. As of 10 a.m. Wednesday, February 17, 2021, for Gas Day Thursday, February 18, 2021, natural gas at Demarc and Ventura locations have traded between $20 to $30/Dth; however, Field Area trading locations in the Permian and Waha areas are trading around $65/Dth. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantities. Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity. Refer to Tariff Sheet No. 291 for information related to Critical Day provisions. Please continue to monitor Northern's website for updates. If you have any questions regarding this notice, please contact your marketing or customer service representative. DDVC penalties are applicable to the bumped shipper's quantity.

NNG and NiGas Critial Notices for February 13-18

NiGas Multi-Day Critical Notice

(Source: NiGas Email to Customers)

From: Gas Nomination System
Sent: Thursday, February 11, 2021 1:46:18 PM (UTC-06:00) Central Time (US & Canada)
To: Kelsey Sefcik
Subject: NicorGas Critical Days 2/13-15

This Message originated outside your organization.

Nicor Gas Critical Day Declared
February 13, 2021

The Company has determined that a Critical Day will exist for the Gas Day beginning at 9:00 am on Saturday, February 13, 2021 and is anticipated to continue through the Gas Day Monday, February 15, 2021

Nominations will be accepted if received by the Company no later than 8:00 am Central Standard Time of the Critical Day. During the Critical Day, customers are limited to storage withdrawals and Company supplies based on their applicable tariffs and contracted quantities.

The Critical Day is being called as a result of severe cold weather in the Nicor Gas service territory.

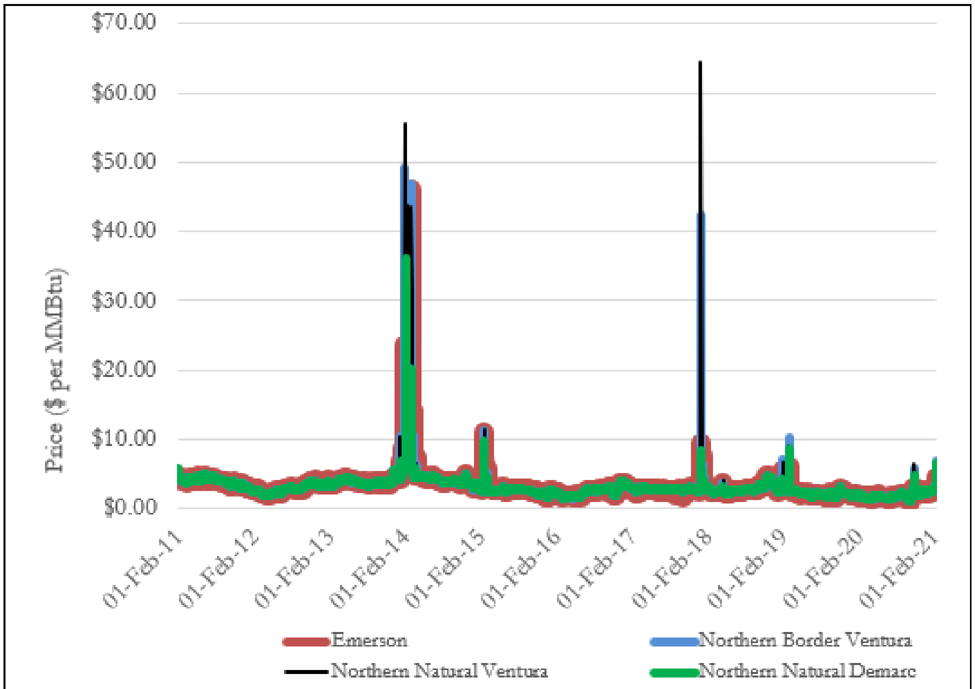
Customers and shippers should refer to their particular rate and tariff for specific language related to the applicability and charges for Unauthorized Use. Customers should note that the charges for Unauthorized Use may be significant. Additionally, Requested Authorized Use will not be available.

Nicor Hub interruptible withdrawal services will not be available. Injections will be accepted.

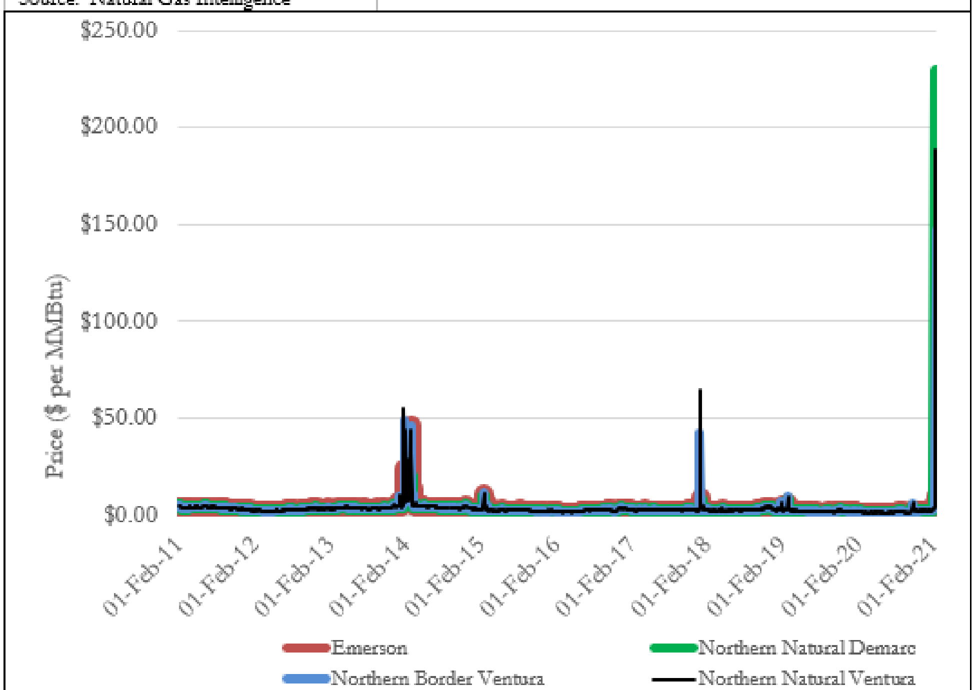
While the Critical Day declaration is currently limited to the Gas Days of Saturday, February 13, 2021, Sunday, February 14, 2021 and Monday, February 15, 2021; pipeline deliveries and storage operations will be monitored closely throughout this period with additional action taken as necessary.

We are providing this notice so shippers will be prepared to make arrangements in the event further action is required. We encourage shippers to closely monitor the Bulletin Board for changes. Nicor Gas will make every effort to afford shippers as much notice as possible.

Historical Price Behavior



Source: Natural Gas Intelligence



Source: Natural Gas Intelligence

Statistics on Past Price Spikes

February 1, 2011 – February 11, 2021

	Emerson	Northern Border Ventura	Northern Natural Ventura	Northern Natural Demarc
TEN YEARS				
February 1, 2011 through February 11, 2021				
Maximum Price	$45.95	$49.30	$64.49	$36.11
Days Above $5.00	61	64	64	50
Percent of Total Days	2.46%	2.58%	2.58%	2.02%
Longest Duration Above $5.00, days	27	36	38	35
Days Above $10.00	4	18	17	5
Percent of Total Days	0.73%	0.69%	0.20%	0.00%
Longest Duration Above $10.00, days	2	9	9	2
FIVE YEARS				
February 1, 2016 through February 11, 2021				
Maximum Price	$9.40	$42.47	$64.49	$8.55
Days Above $5.00	5	11	11	4
Percent of Total Days	0.40%	0.88%	0.88%	0.32%
Longest Duration Above $5.00, days	3	5	5	2
Days Above $10.00	0	2	1	0
Percent of Total Days	0.16%	0.73%	0.69%	0.20%
Longest Duration Above $10.00, days	0	1	1	0