REPORT ON THE NATURAL GAS PRICE SPIKE OF FEBRUARY 2003

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In late February 2003, United States production-area prices for natural gas rose sharply and quickly in response to physical market conditions leading to low supply and high demand for a short time. These conditions influenced prices across the North American continent. In addition, some Northeastern and Midwestern consuming areas faced additional price increases because of limits on the industry's physical capacity to deliver sufficient natural gas to meet elevated customer demand due to a cold front. Deliveries were limited, in part, due to low storage inventories. Similar natural gas price spikes are possible when episodes of cold weather occur at times when storage inventories are limited.

The Federal Energy Regulatory Commission assigned an investigating team (the Team) to analyze the situation, and to coordinate as needed with the Commodity Futures Trading Commission (CFTC) on their analysis.

The Team's detailed analysis of a large sample of thousands of physical natural gas transactions and subsequent interviews with various market participants yielded no evidence of market manipulation. The many physical and financial markets that together constitute the larger North American natural gas market appeared to operate effectively through the spike. Prices in these markets rose in apparent response to underlying supply and demand conditions, and in a manner consistent with those conditions.

Natural gas markets in the last week of February 2003 consisted of relatively few buyers and sellers, too few of which were engaged in active trading. While less robust markets increase the possibility that these markets may not respond adequately under stress, market thinness and concentration are evidence of the *potential* for inefficient prices or manipulation, not *evidence* of those problems. Increased numbers of active traders in these markets would improve liquidity and reduce concentration and a rebound of the energy trading industry would probably improve performance.

THE FEBRUARY PRICE SPIKE

During the week of February 24, 2003, natural gas prices for physical next-day delivery across the country spiked – effectively tripling in certain regions. Figure 1 below shows price behavior around that time for production areas (Henry Hub, Louisiana), consuming areas (Chicago, New York City at Transco Zone 6, and West Texas at Waha) and futures markets (delivery for the next month at Henry Hub).

Prices changed the most on February 24 when Henry Hub next-day prices ranged from $8.00 to $16.00/MMBtu.[1] The following day, February 25, Henry Hub prices reached an all-time high of $22.00/MMBtu with a reported mid-point price of $18.60/MMBtu. Other production area prices reached similar highs.

Prices for New York City momentarily reached $40.00/MMBtu and finished the day on February 25 in the upper $20.00/MMBtu range. Chicago prices rose on February 25 in alignment with production area prices and then spiked again on February 28.

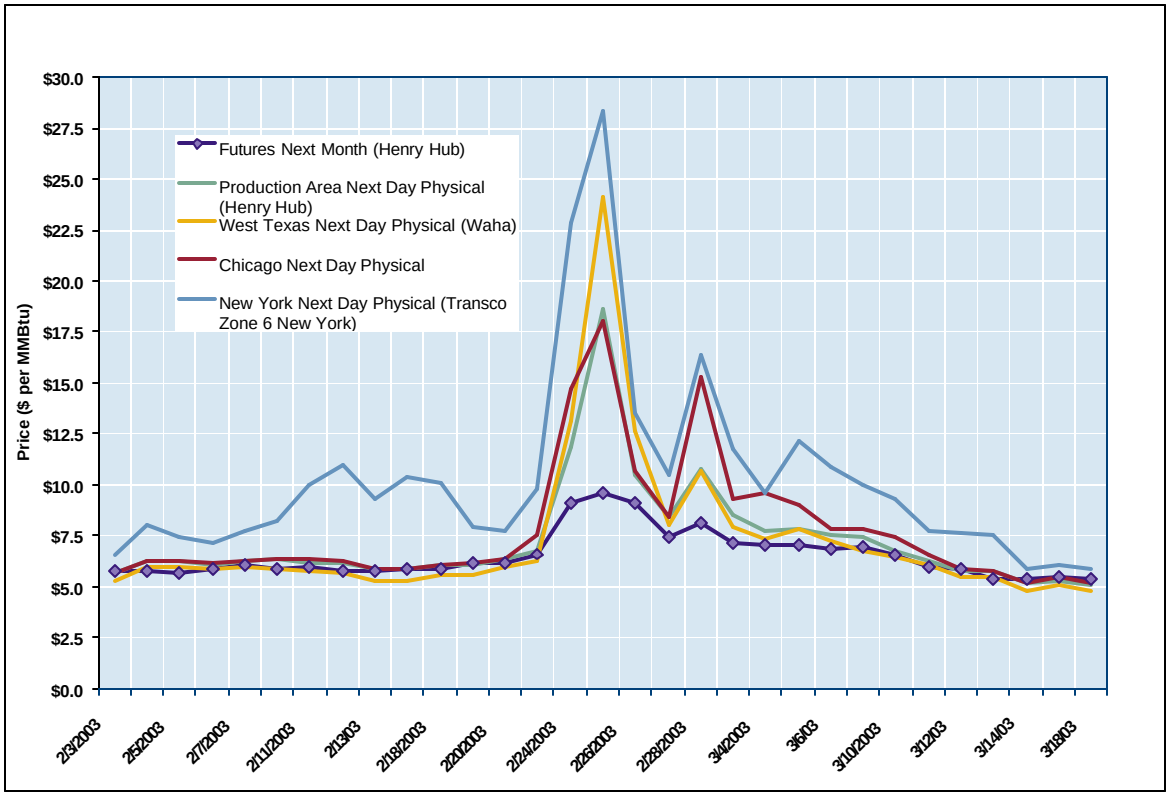

Figure 1: Spiking Natural Gas Prices Were National in Scope
Sources: NYMEX for futures settlement prices and Gas Daily next day physical prices

[1] Unless otherwise identified, daily physical market prices are reported from *Gas Daily* during that period.

The futures price for the March 2003 contract reacted in the same direction during the spike, but did not rise as far.[2] The reaction of the futures market in the same direction at the same time shows how closely the physical day-ahead and financial monthly markets are linked. The smaller effect on futures prices indicates that traders saw the spike as the short-term phenomenon it turned out to be and understood that price pressures were likely to moderate during the following months.

The next section of this report shows that natural gas markets were under great stress during late February 2003, primarily because cold weather significantly increased demand and reduced storage inventories. The following section reports on our examination of a large portion of the market behavior during the period and finds no evidence of market manipulation. At the end, the study summarizes findings.

Figure 1 underscores the fact that the price spike was short, national in scope, and affected different regions differently. To understand the reason for the price spike, we need to consider the national and regional factors that led to it.

DEMAND, SUPPLY AND PHYSICAL FACTORS

National factors explain the basic pattern of the price spike.

At the national level, important demand and supply factors included:

- A Cold Front. A cold front drove down temperatures across much of the eastern half of the United States during that last week of February. At the same time, forecasters expected cold weather into early March. The eastern United States represents a large proportion of overall natural gas demand. This cold weather and the associated heating needs raised demand to high levels – not the highest of the winter but high for late winter.
- Sustained Cold Weather and its Effects. The cold weather in late February came at the end of an unusually cold winter in the eastern half of the United States, as shown in Figure 2. As a result, as shown in Figure 3, storage inventories in production and eastern consuming areas were much lower than normal after heavy winter withdrawals – 42 percent lower than the late February 5-year average of 1,446 billion cubic feet. In general, low inventories lead to low pressure in storage reservoirs, reducing the amount of natural gas they can deliver on any day. This effect cut the supply available to meet the kind of peak demands faced that week.
- Well Freeze-Offs. The cold front penetrated producing areas, particularly in the Mid-continent, freezing-off some wells. Well freeze-offs shut off production until they could be fixed, reducing supply availability temporarily.

[2] This report includes analysis of some natural gas futures and options trading data from the New York Mercantile Exchange (NYMEX). This information was provided to the Commission by the CFTC. This report is, however, solely the product of the Commission's Investigating Team and does not represent the analysis of the CFTC or its staff.

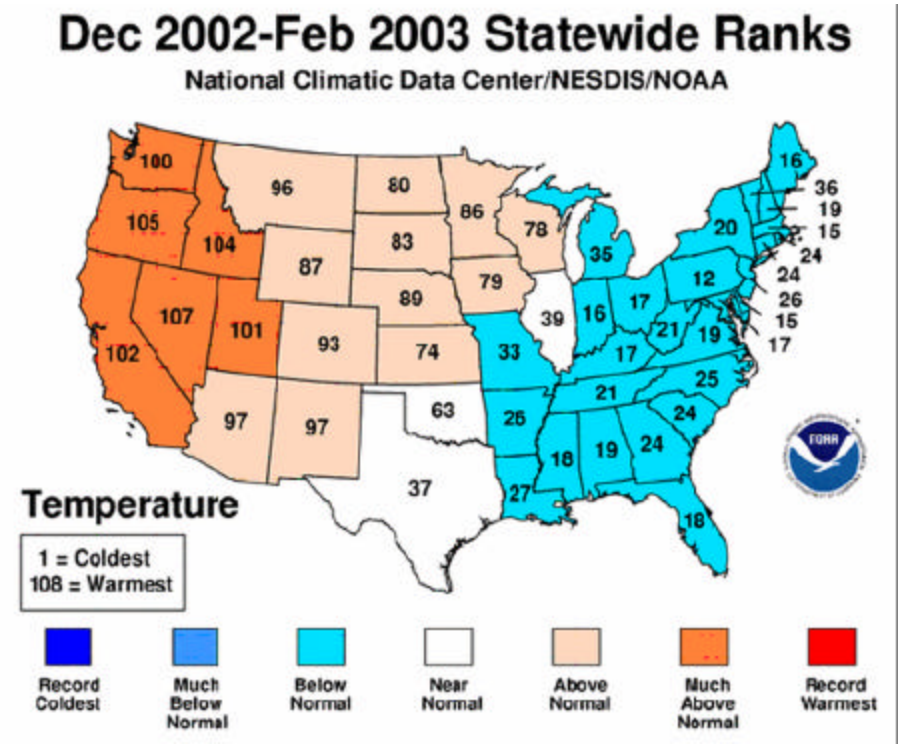

Figure 2: Cold Weather Drove Winter Natural Gas Demand
(Average February 2003 Temperature by State Compared to the Last 108 Average February Temperatures)
Source: National Oceanographic and Atmospheric Administration

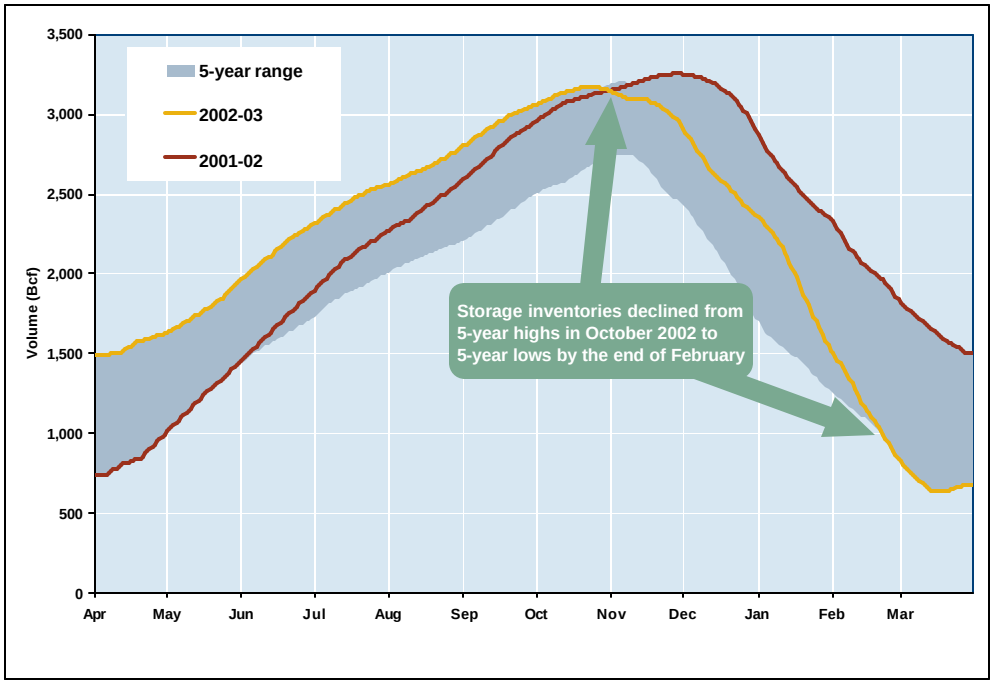

Figure 3: National Storage Inventories Were at the Low End of the 5-Year Range during the Price Spike
Source: American Gas Association (before May 2002) and Energy Information Administration (since May 2002)

Overall, the nation faced high, short-term demand for natural gas at the same time as there was a reduced ability to deliver natural gas. The result was predictable: higher nationwide prices for a short period until weather patterns moderated. Similar conditions have led to less severe price spikes in the past. Similar conditions could create price spikes in the future.

Additional price increases occurred regionally due to pipeline and storage limits.

Certain regions, including the Northeast, the Midwest, and West Texas, saw larger price increases than in producing regions. Others, such as California and the West, saw no additional price increases.

To examine these regional differences, the Team collected pipeline-specific capacity use information. In addition, the Team conducted follow-up interviews with representatives of interstate pipelines serving the Northeast and the Midwest, electric generators, local distribution companies, and state agencies. Based on this information, the Team found no evidence of manipulation of pipeline or storage capacity in order to affect regional prices. In summary, the Team found:

Northeast. Prices increased more in the Northeast than nationally because of physical delivery limitations. The Team verified that pipelines serving the region were full between producing and consuming areas. Many had to issue special instructions (known as Operational Flow Orders or OFOs) limiting how customers could use the systems. To illustrate these effects in the Northeast, we will review prices for New York City. Figure 4 shows how cold New York was each day of the price spike[3], the daily price of natural gas, and the timing of major OFOs. Pipelines were not as full between major storage fields and consuming areas as they had been earlier in the winter, because of the reduced ability of storage fields to deliver.[4] Indeed, several storage field operators imposed constraints on customer use of storage for that reason.

Prices do not exactly track heating degree days, because at some point when heating degree days go up (it gets cold), pipeline delivery capacity reaches a limit. At that point in markets, the price rises to reduce demand. We see this effect on Figure 4 in particular in New York on February 25, 2003.

Some market participants reported to the Team that the higher demand in the Northeast described above had driven many buyers into the spot market, thus forcing up the price.

- **Midwest**. Broadly, issues in the Midwest were similar to the Northeast. Like Figure 4, Figure 5 shows how cold Chicago was each day of the price spike, the daily price of natural gas, and the timing of major OFOs. As in the Northeast, operational failures limited pipelines' ability to serve the market during the critical period.

[3] Measured in heating degree days – the number of degrees below 65 degrees Fahrenheit

[4] In effect, most natural gas storage operates much like a balloon. When it empties, there is less pressure. Consequently, it produces less on any day or hour than when it is full.

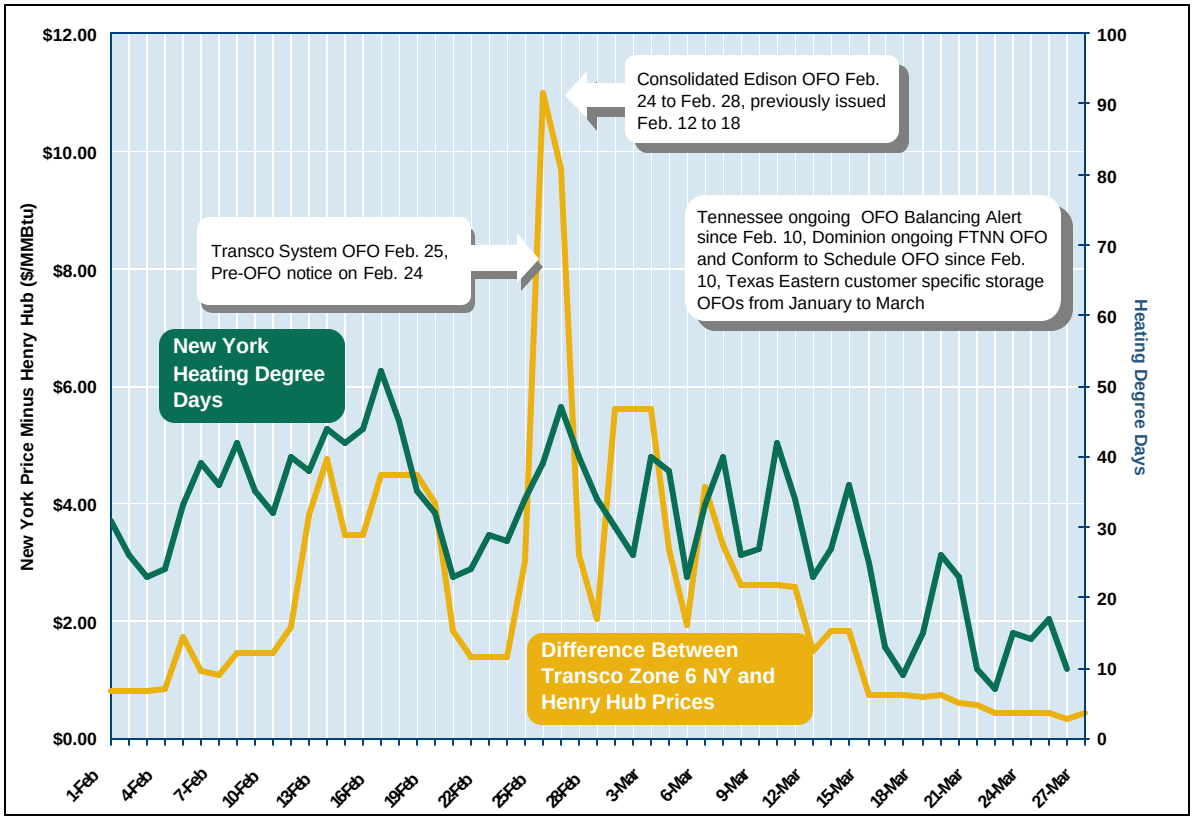

Figure 4: Timing of Weather and OFOs Affecting the New York Natural Gas Market during the Price Spike
Source: Gas Daily and wunderground.com

- **West Texas**. Prices also increased more in West Texas than at Henry Hub. This increase resulted directly from local well freeze-offs and high electricity demand within Texas. As a result, market participants reported that many generators could not meet ERCOT's[5] call for more power because they could not buy natural gas in the spot market.[6]
- **California and the West**. Weather in the west was relatively mild compared to the eastern United States. As a result, infrastructure did not limit delivery and force up natural gas prices. Western price movements followed closely supply area movements.[7]

[5] The Electric Reliability Council of Texas

[6] For further information regarding effects of the Price Spike in Texas, see "Market and Reliability Issue Related to Extreme Weather Event on February 24-26, 2003," Project Number 25937 of the Public Utility Commission of Texas, Market Oversight Division, May 19, 2003.

[7] For further information regarding effects of the Price Spike in California, see "Natural Gas Market Price Report," California Energy Commission and the California Public Utilities Commission, March 28, 2003 with monthly updates including the latest on July 1, 2003.

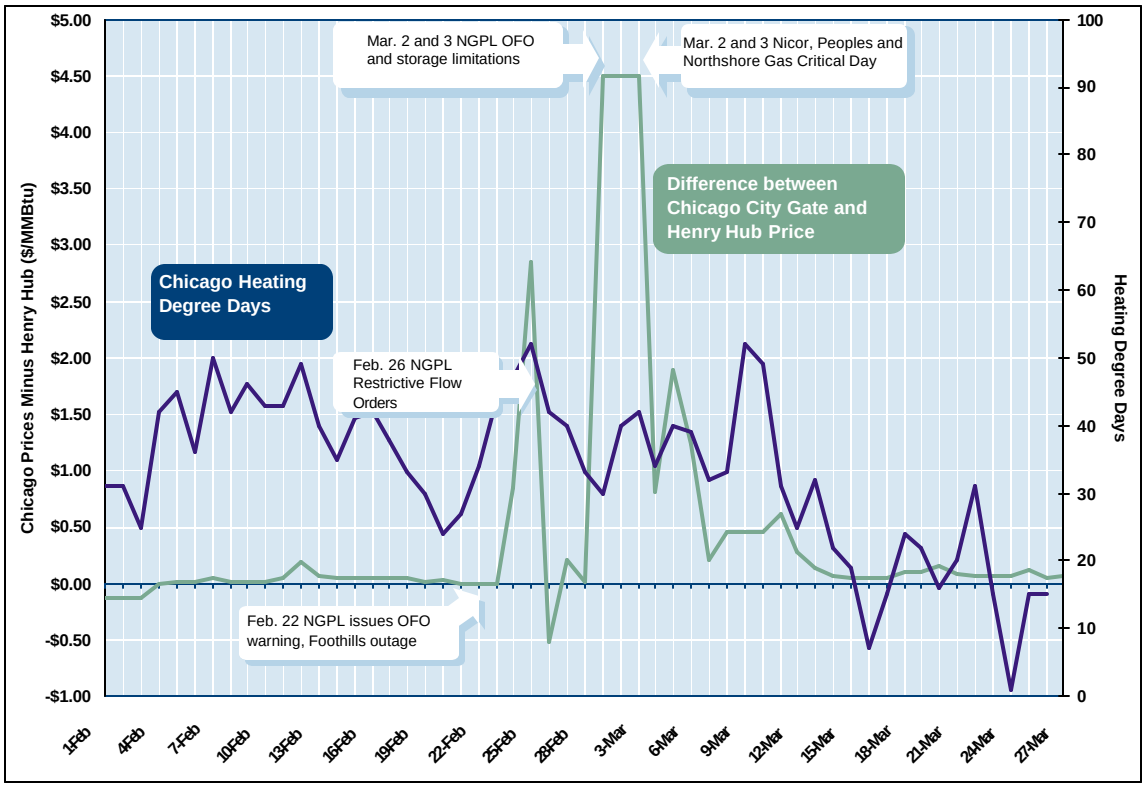

Figure 5: Timing of OFOs Affecting the Mid-western Markets during the Price Spike

Source: Gas Daily and wunderground.com

In general, the Team found that natural gas price movements across the United States and regionally appeared to behave as expected given the prevailing supply, demand and regional capacity limitations. However, the Team decided that it was necessary to examine specific market behaviors to assure market participants and others that markets performed effectively. The next section will discuss that analysis.

MARKET BEHAVIOR

In addition to fundamental (supply, demand and delivery constraints) factors, the Team examined an extensive sample of transaction data to determine whether trader behavior exacerbated the price spike. In particular, the Team analyzed transactions executed in physical and some financial natural gas markets during late February to look for evidence that any trader might have engaged in behavior designed to manipulate prices.

The Team was unable to analyze all natural gas transactions because these markets are not traded in centralized exchanges, so there is no central repository for information about natural gas transactions. To collect a reasonable sample of transactions, the Commission subpoenaed sixteen over-the-counter natural gas brokers, including both "voice" brokers and electronic trading facilities like the Intercontinental Exchange (ICE), for information related to all natural gas trades, bids and offers during the week of the spike.

The resulting data set included over 10,000 trades and over 100,000 bids and offers for both physical and financial natural gas products for more than 100 locations across the United States. Based on strong anecdotal evidence, the Team believes the data set represents more than half of next day physical trades, the most relevant product markets given the short-term, fundamentals-driven nature of the spike.[8] Transactions not included in the sample include deals done directly between traders and NYMEX transactions.

Detailed analysis of this transaction sample showed no signs of market manipulation. Analysis of the sample data included, but was not limited to assessments of trader activity levels, effectiveness of the way certain markets relate to one another, actual patterns of trading and human intelligence. We will consider each of these tests in some detail.

Trader activity tests show some thinness and concentration.

When markets have too few active participants, or when a few participants have a disproportionate share of the activity, then they are at higher risk of not functioning well. We call markets with these characteristics "illiquid" and "concentrated." Liquid markets are ones where a trader can easily buy or sell at a prevailing price with relatively low transaction costs, and are characterized as having many participants, many of whom are actively trading.

Physical natural gas markets, because they are so fragmented by geographical location and by timing of delivery (e.g., daily, monthly, longer-term), often face problems with liquidity. The Team's analysis supports this conclusion.

[8] In the April 24, 2003 Staff Conference on Natural Gas Price Formation, Chuck Vice, Senior Vice President and Chief Operating Officer of ICE asserted that he believed that ICE handled 70% of day-ahead physical natural gas transactions (p. 33 of the transcript). The investigating team interviews with traders confirmed opinions that ICE represents between 50% and 70% of their day-ahead physical natural gas transactions. Additionally, in the June 24, 2003 Technical Conference on Natural Gas Price Formation, three trading panelists confirmed that transactions with ICE and voice brokers are "representative" of this market (pp. 239-249 of the transcript).

ICE Market Location	Number of Traders	Number of Sales	Volume (MMBtus)	Concentration Ratio of 4 Largest Buyers (Volume %)	Concentration Ratio of 4 Largest Sellers (Volume %)
Production Area:					
Henry Hub	32	76	1,069,733	56.7	48.9
New York:					
Transco Zone 6 New York	14	15	104,533	81.0	68.6
Chicago:					
NGPL, NICOR	22	41	440,017	71.3	55.4
PGLC	17	22	257,650	67.9	66.4
West Texas:					
El Paso Keystone	15	16	176,083	69.7	70.5
Waha	10	15	180,700	88.6	81.1
California:					
PG&E Citygate	16	28	497,317	78.9	65.9
PGT Malin	12	13	173,217	82.6	69.7

Table 1: Average Daily Next Day Physical Natural Gas Trading Activity as Sampled on ICE Over the Week of the Price Spike (February 21 through February 28, 2003)

Table 1 shows trading statistics on ICE for physical day-ahead natural gas markets in the geographical locations discussed above for the period from February 21 through 28, 2003. The most actively traded location reported in the table is Henry Hub, with an average of 32 traders that executed 76 transactions for over a billion cubic feet of natural gas each day of that period. Of the daily average of 32 traders, the largest four buyers averaged almost 57 percent of the natural gas purchased, the largest four sellers 49 percent of volumes sold.[9] (Other locations, particularly in production areas, were as actively traded.)

Liquidity and concentration measures for the regional markets are less robust than Henry Hub. However, numbers of traders and transactions are not significantly different than normal as measured using averages noted by ICE for the first four months of 2003. Recently, ICE through its 10X subsidiary has begun to publish the data related to number of traders and trades, and volumes along with volume-weighted average prices for these markets on a daily basis.

By definition, because Table 1 was generated using a sample of the market – albeit a large sample – Table 1 understates trading activity and may overstate concentration somewhat. In addition, there are no direct comparisons to these physical natural gas markets to use as benchmarks.[10] Also, concentration ratios are evidence of the *potential* for inefficient prices or manipulation, not necessarily *evidence* of those problems. Still, increased numbers of active

[9] This study uses a four trader concentration measure to emulate, as closely as possible, concentration ratios used in the CFTC's weekly Commitment of Traders reports. However, the CFTC's measure is of open interest, which is not the same as volumes sold. Our measure of trading concentration cannot be directly compared – underscoring the difference between the structure of physical and futures markets.

[10] NYMEX natural gas futures as of February 25, 2003 had 176 traders with open interests for all 72 months traded. Concentration in the futures market is measured not by numbers of trades, but by open interests (size of positions held) at the end of the week. Using that alternate measure, on February 25, 2003, natural gas futures had 4 trader concentrations of 19.4% for net sellers and 26.6% for net buyers as reported in that week's "Commitment of Traders Report."

traders in these markets would improve liquidity and reduce concentration and a rebound of the energy trading industry would probably improve performance. The next three analyses of market relationships, trading behavior and human intelligence are more direct evidence.

Markets appear to have related to one another effectively.

Minute-by-minute comparison of transactions through voice brokers and on ICE for various physical natural gas markets tracked each other consistently through the last week of February. The Team considered these relationships over time, geographically, and between look-alike products.

As demonstrated previously in Figure 1, prices in the futures market for March delivery to Henry Hub changed less than in the Henry Hub physical next-day market. During the entire week of February 24, there was a substantial difference between these two markets. Though lower than the day-ahead physical high price, March futures hit an all-time high price of $11.899/MMBtu during early morning electronic trading on February 25, 2003. Figure 6 shows that the March futures price reached that high for only one trade, and traded above $10.00/MMBtu for only a few hours in overnight electronic trading.

The fundamentals-driven rise in the short-term physical market did not have as a great dollar effect on the futures market for the March 2003 contract *because traders did not expect the price pressures to persist*. Indeed, within two or three weeks, physical market prices returned to its historical relationship with futures prices. A short-term premium of physical markets to futures prices makes sense given the nature of the spike.

Figure 6: March NYMEX Natural Gas Futures Trading Reached a Brief $11.899/MMbtu High in Before-Hours Trading in the Morning of February 25.
Source: NYMEX from nymex.com

To assess geographic relationships in more detail, the Team analyzed the price and timing of short-term fixed price physical and financial transactions at 23 trading locations in the Gulf Coast near Henry Hub on February 24. Figure 7 on the next page shows that transactions in all these markets reacted similarly throughout the day.

Because these 23 locations are relatively close to one another physically (near the Louisiana Gulf Coast), trading in those areas tends to fall in a relatively close band. Erratic relationships could have been evidence of a number of factors including capacity constraints in the area or manipulation of pipelines, storage, or markets. None of these erratic relationships were found.

The Team performed the same analysis on five Northeast trading locations, and Figure 8 shows a similar result. Together, Figures 7 and 8 show similar timing for price movements between the production and this consumption region as well, though the movements were different in magnitude as discussed in the regional assessment of fundamentals above.

Finally, to test for similar behavior in similar products, the Team compared minute-by-minute prices for March 2003 and April 2003 natural gas futures against monthly swaps traded on ICE and designed to function much like futures. The prices for both products tracked each other closely, showing the strong link between those markets.

In all cases, trading in comparable markets behaved as expected. Because of the short-term, physical nature of the pressure on prices, prices in shorter-term markets spiked higher than in longer-term markets, with an apparent premium on physical delivery. Geographically, prices moved disproportionately to the rest of the country where capacity constraints applied.

This collection of observations indicates that markets appeared to have related to one another relatively effectively, not creating large, apparent, unused opportunities to make money by trading between two markets.

Analyzed patterns of trading did not offer evidence of manipulation.

Reviewing actual patterns of trading is the most direct way to search for potential manipulation. For this study, the Team performed overlapping, detailed reviews of the sample information described above. In its extensive analysis of the transaction sample, described below, the team found no evidence of market manipulation.

The first steps of the analysis included construction of minute-by-minute timelines of trading in the most significant markets making use of 16,488 sample transactions and the 138,446 sample unconsummated bids and offers (from ICE) in various physical and financial natural gas markets covering key locations across the overall United States natural gas pipeline delivery system.

These timelines were used for detailed examinations of trading patterns, identifying times when prices of transactions changed most abruptly and identifying the traders most active during those periods. The activities of those traders was reviewed both in the context of the overall market, and individually in order to develop theories regarding their strategies. Multiple analysts reviewed these data using different analytic tools and approaches to increase the likelihood of finding suspicious patterns. These analysts periodically compared their overlapping findings to coordinate the analysis.

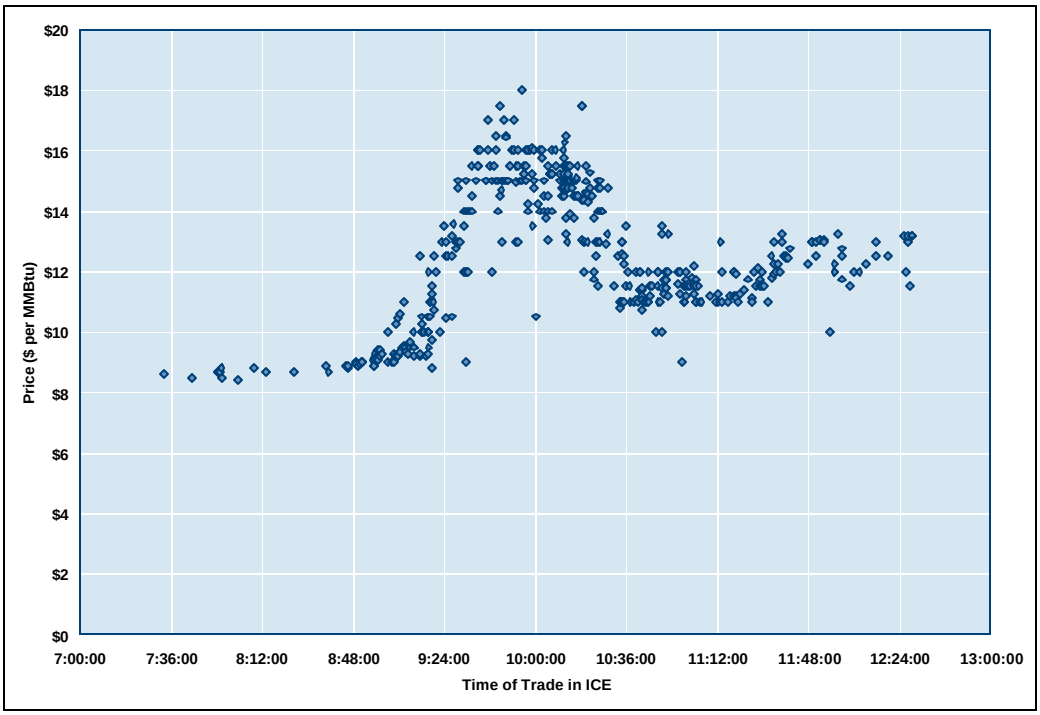

Figure 7: Natural Gas Prices in Gulf Coast Markets near Henry Hub Traded Together Closely on the Day of the Largest Price Movement During the Price Spike

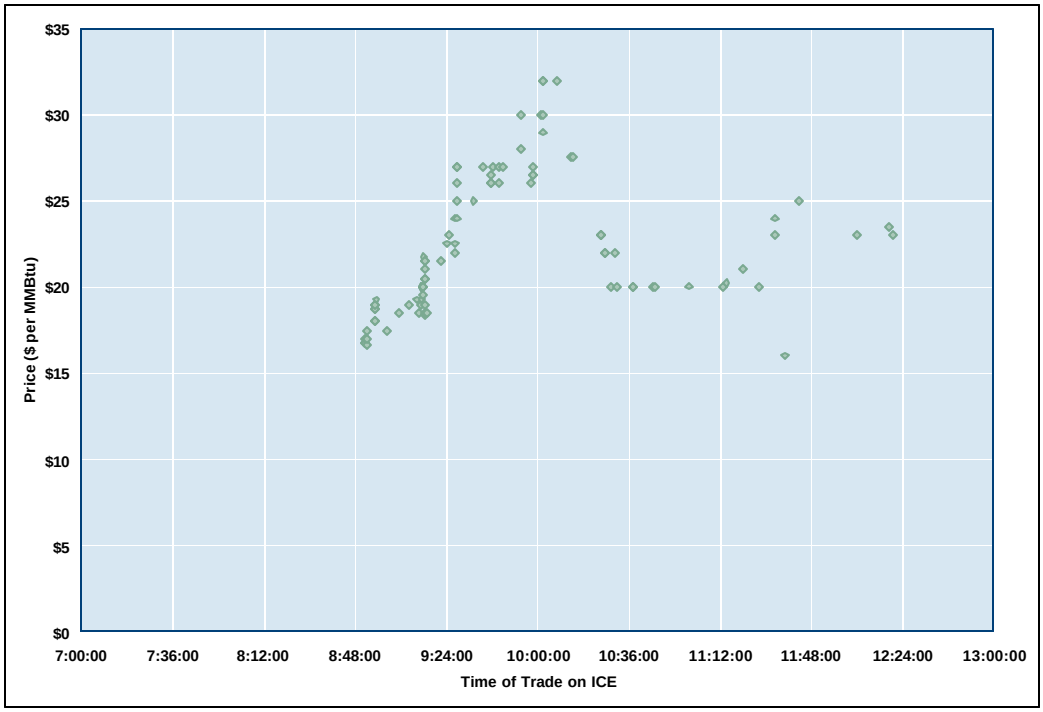

Figure 8: Natural Gas Prices in Northeastern Markets near New York City Traded Together Closely on the Day of the Largest Price Movement During the Price Spike

Analysts searched for patterns within products, for specific traders, and for product-trader combinations. The additional markets analyzed were chosen based on prices, size, liquidity and concentration. Specific company bids, offers, and trades reviewed were chosen based on size, number, unusual timing, and potential price-leading behavior among other considerations.

The first set of markets examined were those trading products for the next day physical and balance of month "swing swaps" for February.[11] A total of 6,520 next-day physical and balance of month swing swap transactions were grouped by delivery points into specific geographical regions. Each region was charted by day to focus on the relationships between the delivery points (as discussed above) and then the regions were compared to each other on a daily basis for trading from February 21 to 28. Using these timelines, Team analysts identified and reviewed low and high prices each day as well as periods of sharp price increases and declines.

A second set of timelines were created for those companies that executed a significant volume of the transactions in each geographic region. These timelines were reviewed for patterns that would indicate that a particular trader was "leading" prices during sharp price increases or declines. No significant situation involving "leading" of prices was identified.

A third set of timelines was created to compare March 2003 and April 2003 swaps settling against the NYMEX expiration price and executed through voice and online brokers tied to March 2003 and April 2003 natural gas futures.[12] In these timelines, prices corresponded closely. A final set of timelines examined plotted prices for next day physical delivery versus March futures transactions (compared on a daily basis in Figure 1). The February next day physical price was found to trade at a premium to the March 2003 futures contract for the fundamental reasons described earlier.

Within each individual company's activities, analysts looked for patterns of trades in one product which seemed inconsistent with their trades in another product. Additionally, the counterparties within each transaction were checked to see if they had consistently transacted with one another and if there were patterns within the trades between pairs of counterparties.

The Team was able to identify behaviors reflective of a wide range of company-specific business strategies. These included evidence of various gradations of strategy from straightforward supply procurement and sales activity through more active trading of positions. Subsequently, the Team held detailed follow-up interviews with eight of the most active traders in order to verify the Team's theories regarding their strategies and identify other trading activity outside the sample.

In its extensive review of the transaction sample described above, the team found no evidence of market manipulation.

[11] Because trading that week was at the end of the month of February 2003, balance of the month products overlapped the timing of the price spike as well as the next day delivery market. "Swing swaps" are financial hedges that relate directly to prices in the next day physical market.

[12] "Swaps" are financial products that, in effect, trade one price for another, with a payment made based on that difference. For example, the buyer of a swap might agree to pay the difference between a fixed price and a price determined later in a market.

No additional evidence of manipulation was found from Hotline calls or trader interviews.

The Commission Hotline[13] was monitored for calls regarding manipulation during the February price spike. The Team also explored price spike market conditions in interviews with large buyers and sellers.

One contact was made with Hotline staff expressing concern about the price spike, but the caller did not provide material information regarding market manipulation.

Interviewed industry participants did refer to a widening of the difference between where, from moment to moment, offers to sell and offers to buy would stand – known as the "bid/ask spread." The size of this difference reflects many things including the competitive pressures on the markets, the level of liquidity and the mix of trading companies' relative credit strength. A widening of bid/ask spreads was consistent with the forces on the markets at the time. No trader interviewed indicated that this was crucial problem.

[13] Call toll free at 888-889-8030, locally at 202-502-8390 or email at hotline@ferc.gov.

FINDINGS

After rising steadily last winter, natural gas prices in various physical and financial markets spiked in the United States in late February, reaching a peak of $22.00/MMBtu for physical day-ahead delivery in producing areas on February 25, and topping $30.00/MMBtu in some Northeastern and Midwestern consuming areas. This study summarizes the Federal Energy Regulatory Commission's investigating team's analysis of the February price spike, examining both market fundamentals and the behavior by energy traders in key markets.

The Team concludes that:

- United States production-area prices spiked as a result of short-term conditions leading to low supply and high demand. These conditions affected prices continent-wide. In particular, a cold front over the Eastern half of the United States significantly increased natural gas demand at the same time that gas deliverability declined due to low, late-winter storage inventories that reduced the ability to withdraw natural gas from storage and from some cold-weather well freeze-offs.
- Some Northeastern and Midwestern consuming areas faced additional price increases because of a limited ability to deliver natural gas to customers in these areas. The Team verified that pipelines from producing areas were full and storage withdrawals in market areas were inadequate to meet the additional demand, so that natural market dynamics should have caused these price increases.
- Similar natural gas price spikes have occurred historically when episodes of cold weather occur at times when storage inventories are limited. Adequate storage inventory levels entering the coming winter would reduce the likelihood of price spikes in early 2004.
- Detailed analysis of a large sample of physical and financial natural gas transactions that week found no evidence of market manipulation. Extensive interviews with large traders – both buyers and sellers in that week – likewise provided no evidence of market manipulation.
- The many physical and financial markets that together constitute the larger natural gas market appeared to operate effectively through the spike. Prices in these markets rose, but in apparent response to underlying supply and demand conditions and in ways the Team would have expected.
- Natural gas markets in the last week of February 2003 consisted of relatively few buyers and sellers, too few of which were engaged in active trading. While less robust markets increase the possibility that these markets may not respond adequately under stress, market thinness and concentration are evidence of the *potential* for inefficient prices or manipulation, not *evidence* of those problems. Increased numbers of active traders in these markets would improve liquidity and reduce concentration and a rebound of the energy trading industry would probably improve performance.

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