NATURAL GAS AND ENERGY PRICE VOLATILITY

PREPARED FOR THE

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BY THE

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1 Price Volatility in Today's Energy Markets

1.1 INTRODUCTION

Over the last five years, energy price volatility has become the most significant issue facing the natural gas industry and energy companies. Natural gas, electricity, crude oil and oil product markets have all exhibited price volatility for some portion of the period. Price volatility has contributed to a climate of uncertainty for energy companies and investors and a climate of distrust among consumers, regulators, and legislators.

Energy price volatility creates uncertainty and concern in the minds of consumers and producers, who may delay decisions to purchase appliances and equipment or make investments in new supply. Such delay may result in lost market opportunities and inefficient long-run resource allocations. In addition, volatility may create pressures for regulatory intervention that can bias the market and penalize regulated entities and market participants by generating wide and unpredictable revenue swings. Finally, volatility can hurt the image of energy providers with the customers and policymakers and create doubt about the industry's integrity and competency to reliably provide a vital economic product.

However, price volatility in energy markets is a complex issue that affects the various stakeholders in different ways. In addition, price volatility is poorly defined, and there is not a consistent frame of reference for talking about and evaluating price volatility, let alone developing strategies designed to mitigate the impacts of price volatility.

One of the primary objectives of the American Gas Foundation Study on Natural Gas and Energy Price Volatility is to propose methods to mitigate the potential negative consequences of extreme price volatility. However, it is also critical to recognize that energy price volatility plays a necessary role in the operations of our free market energy systems. Energy prices transmit critical information about the balance between supply and demand, moving up and down in order to balance energy supplies with energy demand, both on a short-term, day-to-day basis, as well as over a longer, multi-year investment planning horizon.

The American Gas Foundation Study on Gas Market Price Volatility considers the issue of energy price volatility and the impact of volatility on consumers, industry participants, and the penetration of new technologies such as distributed generation (DG). The study is intended to improve the understanding of the root causes of energy price volatility, to project the likely level of energy price volatility in the future, and to develop strategies to reduce the destructive impact of future volatility.

The results of the study are documented in five chapters. The objectives of this first chapter include:

- Develop an analytical framework to discuss and define energy price volatility;
- Improve understanding of the fundamental causes of energy price volatility and the market conditions that increase price volatility; and
- Describe the impact of price volatility on various market participants including energy consumers and the principal segments of the natural gas industry.

In this chapter of the report, we seek to develop a consistent frame of reference for discussing and evaluating price volatility. We look at alternative definitions of price volatility, as well as evaluating alternative approaches to measure price volatility, and evaluating the impacts of different forms of price volatility. In addition, this chapter of the report includes a series of case studies to examine the causes and impacts of six different widely publicized cases of energy price volatility.

1.2
CONCEPTS OF ENERGY PRICE VOLATILITY

1.2.1 Introduction to Energy Price Volatility

In an efficient market, prices change to correct imbalances of supply and demand. The degree of the imbalance and the ability of producers and consumers to respond rapidly to relieve the imbalance determine the magnitude of the change in prices. In the case of natural gas, the magnitude of the price changes can be quite large under certain market conditions that limit the ability of producers and consumers to respond easily, creating inelastic supply and demand.

Because the demand for natural gas is affected to a large degree by weather, and because weather conditions can change rapidly and unexpectedly, large and sudden shifts in "service demand" can occur that create significant imbalances that must be relieved. Under all but the lowest price conditions, producers market a very high percentage of their total wellhead gas deliverability. Deliverability increases require new drilling activity, which takes three to nine months to affect available supplies significantly. As a result, near-term wellhead production is generally inelastic.

Electricity markets can also exhibit inelastic supply and demand responses, particularly during periods of extremely high utilization of available generating and/or transmission capacity. During those periods, electricity supply becomes almost completely inelastic and small unanticipated outages can cause marginal prices to skyrocket.

1.2.2 Defining Price Volatility

Energy price volatility is a broad and relatively loosely defined term. The impact of volatility on market participants can vary substantially depending upon the specifics being examined. Daily or hourly variations in wholesale prices may be almost irrelevant to the residential energy consumer, but of critical importance to an energy trading company. Similarly, fluctuations in prices in a particular geographic market (e.g., New York City) are very important to customers in that market, but are of only casual interest to people in other market areas (e.g., Chicago).

In order to evaluate energy price volatility, one must fully define the characteristics of the energy prices being examined in terms of:

- Geographic market – the location and geographic scope of the energy market and prices being examined.
- Time interval of the prices – energy price statistics are "averaged" over different time periods.
- Product/point in the energy supply chain – energy is traded at a number of different points along the supply chain.

- Spot prices/retail prices – spot market prices that move with marginal transactions tend to move more than average participant prices that can reflect a portfolio of transactions and can include hedging.

Energy price volatility also can affect participants in two fundamentally different ways:

1) Investment/planning price volatility. Planning price volatility refers to long-term uncertainty in energy price levels that influence investment planning. For example, natural gas producers in today's environment are unsure whether prices in the next one to three years will remain at today's levels (e.g., $3.50 per MMBtu), fall to levels seen early in 2002 (e.g., $2.50 per MMBtu), or increase to shortage-induced levels of $4.50 or higher.

2) Short-term price volatility. Trading price volatility reflects the amount of short-term (day-to-day, or month-to-month) price volatility that influences short-term energy purchasing and hedging strategies.

Geographic Locations

Energy is traded in a number of different locations around the United States. For natural gas, prices are reported on a daily basis in trade publications at scores of locations.[1] As the gas market has evolved, trading volume has grown significantly at a number of these locations such that many of these points have developed into highly liquid commodity markets. Certain points develop particular significance because of the size of the market or because the point is chosen for an exchange-traded product such as futures or options. The Henry Hub associated with the Sabine pipeline in Louisiana is such a point in the natural gas market.

Prices at these locations may be closely correlated for extended periods of time. However, during certain periods, these prices can diverge significantly. Figure 1-1 presents daily spot market prices for three important markets – Henry Hub, New York, and Chicago. It is clear from the graph that spot market prices can vary significantly over a relatively short period of time. In two of the three winters shown, daily spot market gas prices in New York rose to more than $14 per MMBtu. During the winter of 2000-01, gas prices rose dramatically in all three locations. This market behavior will be examined in Section Five of this report.

The graph also shows that prices in these three markets move in a similar pattern (are correlated) during much of the period. But, in February 2000, prices in New York diverged from the Chicago and Henry Hub prices. In the gas market, this type of event is called a “basis blowout.”[2] “Basis blowout” occurs in the gas market when pipeline capacity constraints prevent the movement of additional gas supplies between the two geographic markets.

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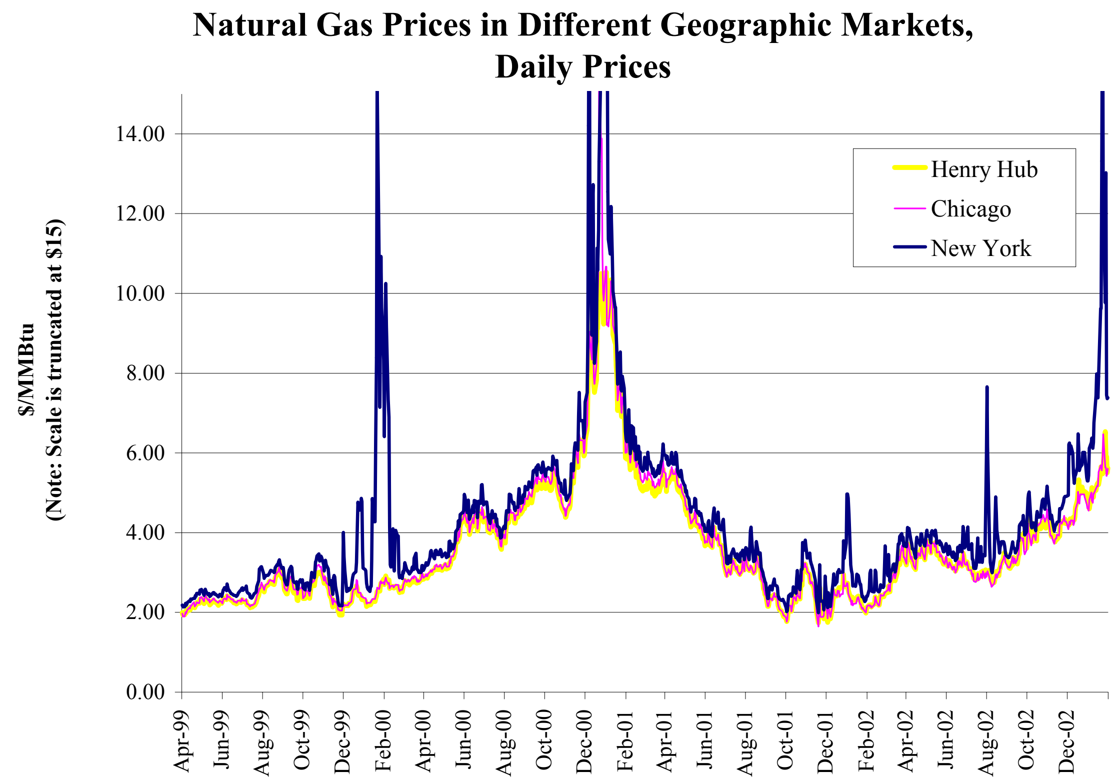
1 *Gas Daily* currently reports prices at 98 different locations.

2 In commodity markets, the term basis is used to describe differences in prices. Three types of basis are commonly tracked: locational basis (differences in prices at different geographic locations), temporal or seasonal basis (difference in prices at different times of the year), and product basis (differences in prices between products that are closely related such crude oil prices and oil product prices).

Figure 1-1



Time Interval of Energy Prices

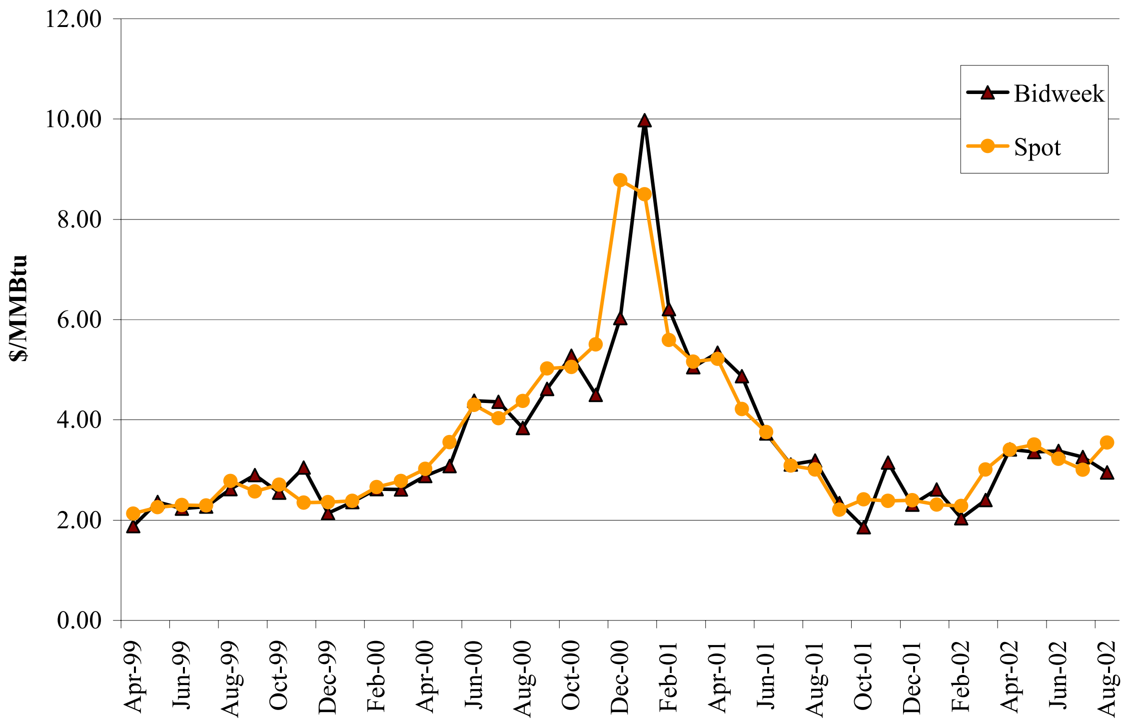
In the natural gas market, gas can be purchased under contracts with a wide variety of contract term length and pricing terms. Within the short-term market, there are two types of contracts that are widely used, with prices that are published in trade publications and used to benchmark other transactions. These are "bidweek" transactions and daily transactions.

"Bidweek" transactions refer to firm commitments to buy or sell a uniform quantity of gas for each day in the following month. The term "bidweek" refers to the final days in the month when contracts for the next month's deliveries are signed. Trade publications collect data from the market participants and compile the prices for monthly firm contracts entered into in the last 5 days, and publish the midpoint and range of the transaction prices. Daily price data is collected in a similar manner for firm transactions for a quantity of gas to be delivered (flow) in the next day.[3] Figure 1-2 presents a time series of bidweek and daily average prices for gas at Henry Hub.

[3] Daily price data can include prices for transactions for a few days of delivery of a uniform quantity of gas. However, the published data only includes transactions entered into on the previous day.

Figure 1-2

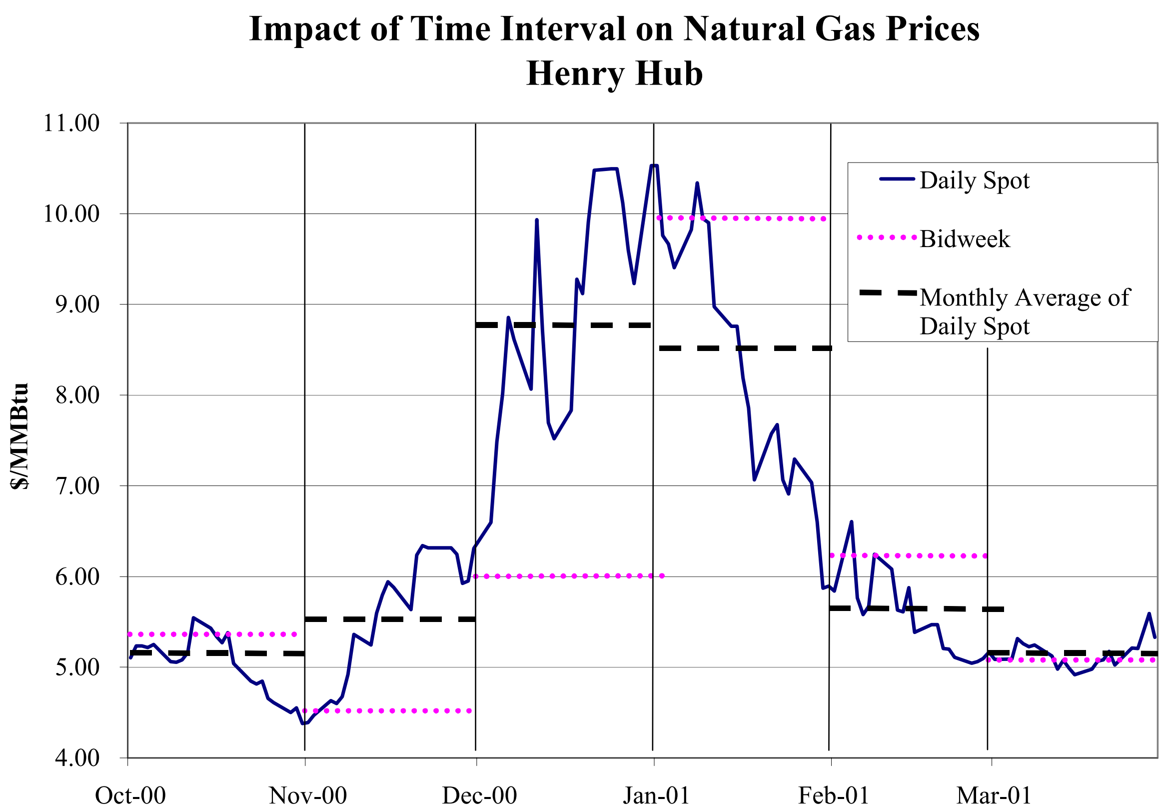
Bidweek vs. Average of Daily Spot Prices at Henry Hub



As the graph shows, bidweek prices and the average of the daily prices are generally close to one another. However, in any given month, the daily price can exceed the bidweek price or the bidweek price can exceed the daily price. Moreover, in some periods the difference can be quite significant. This can be seen more clearly in Figure 1-3. In December 2000, the daily price was $2.75 above the bidweek price. In the following month, the bidweek price was $1.48 above the average of the daily prices.

These gyrations in price relationships can be explained by changes in weather patterns and general market conditions. The bidweek price reflects a “consensus view” of the market conditions for more than 30 days in advance of the end of the period. Given the inaccuracies in weather and market forecasting, the actual market conditions and anticipated conditions can be substantially different. This occurred during the period from December 2000 through January 2001. December 2000 was the third coldest December on record, a fact that was not foreseen in November. And after a very cold first week, January turned relatively mild.

Figure 1-3



In electricity, there are even more time periods to consider. In many markets, such as PJM (the Pennsylvania, New Jersey, Maryland ISO), marginal prices are calculated on an hourly basis. Published data generally presents daily averages for weekdays (excluding holidays). (See Figures 1-4 and 1-5).

Product/Point in the Energy Supply Chain

Energy is priced at a number of points along the supply chain, and the prices at these various points exhibit different behavior patterns. One of the chief causes of these differences is the structure of the market at that point in terms of the degree to which prices are regulated and the form of the regulation.

For natural gas, the structure of the markets along the supply chain presents a complex mix of regulated and deregulated prices. Figure 1-6 presents an overview of the industry supply chain.

Figure 1-4

Impact of Time Interval on Electricity Prices
PJM Western Hub

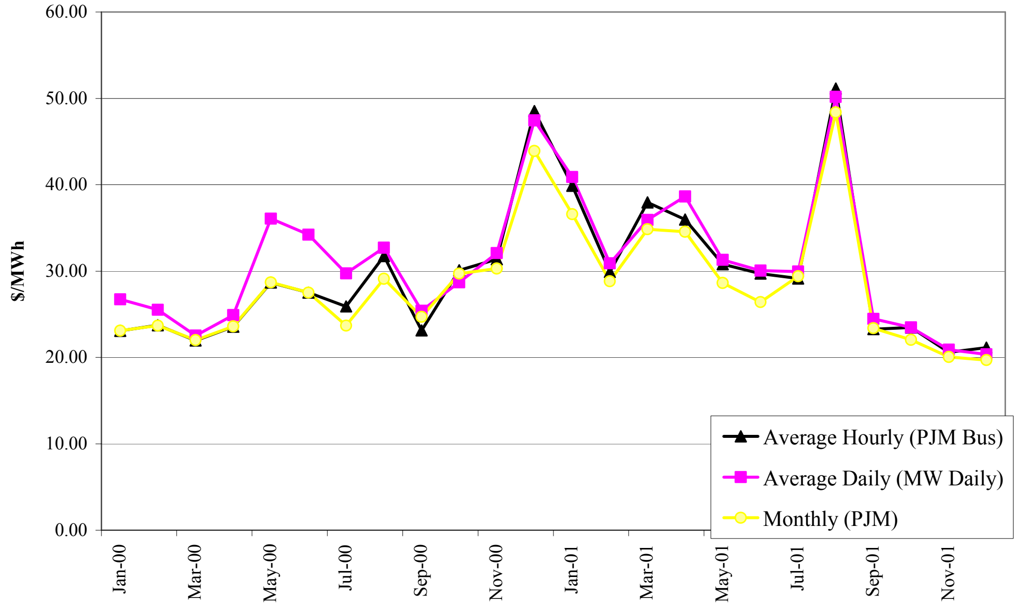


Figure 1-5

Impact of Time Interval on Electricity Prices
PJM Western Hub - December 2000

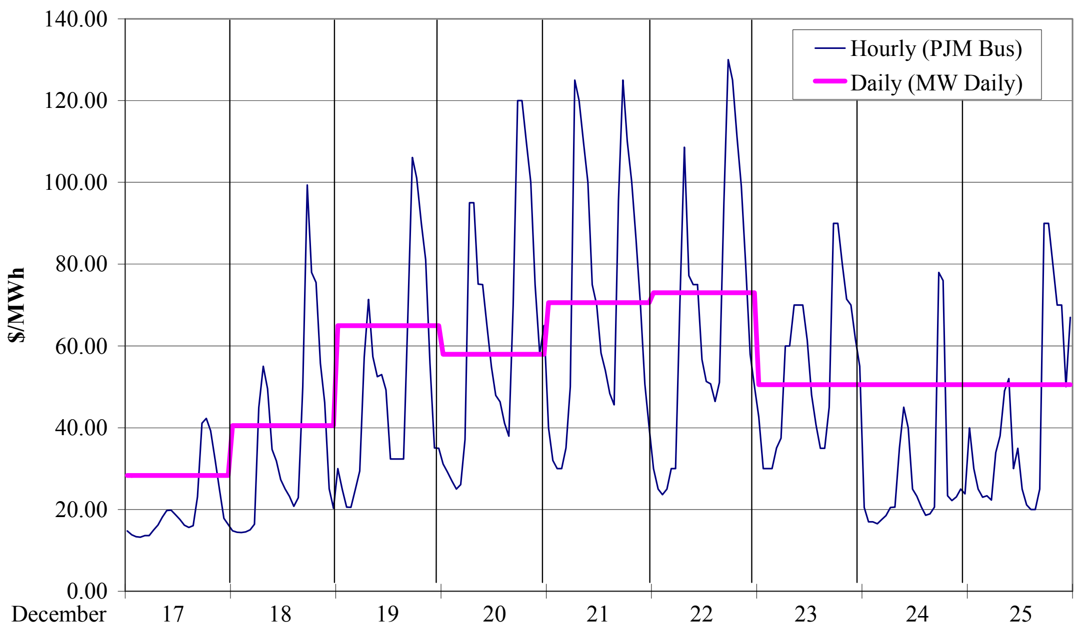
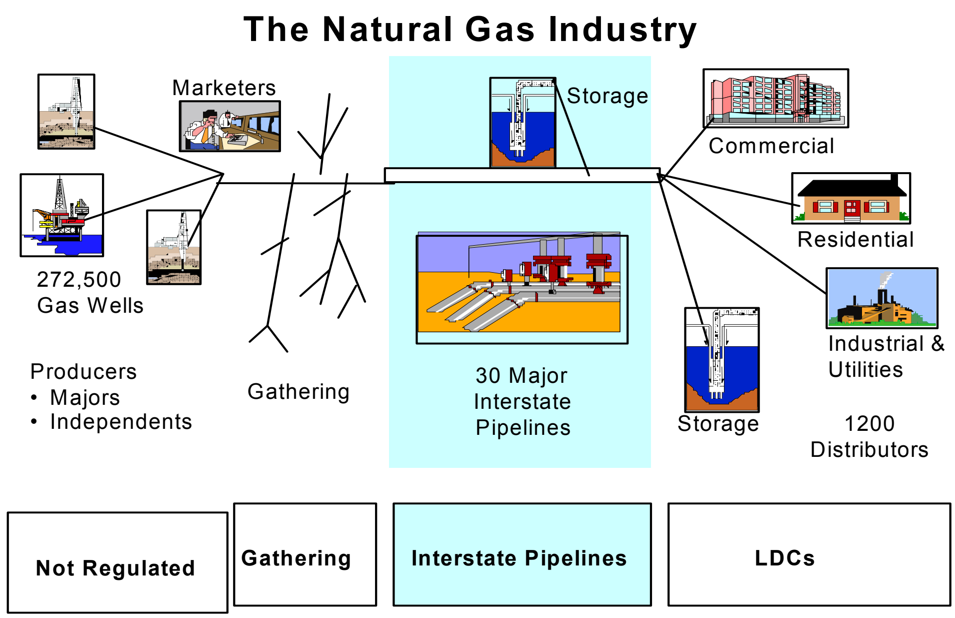


Figure 1-6



The production and gathering[4] components of the natural gas industry are broadly deregulated. The price of the gas commodity itself is deregulated from the point of production through the point that it is delivered to a Local Distribution Company (LDC). However, the Federal Energy Regulatory Commission (FERC) retains jurisdiction over rates charged by pipelines for transportation and storage service as well as the re-sale of transportation and storage services purchased by shippers (i.e., capacity release). The Commission may also have some ability to exercise jurisdiction on the rebundled sale of gas when the gas has been transported on FERC jurisdiction facilities. However, the degree of this jurisdiction has not yet been fully defined by case law.

The price of gas sold by an LDC is generally regulated by the state Public Utility Commission (PUC). In recent years, state PUCs have permitted some flexibility in price regulation for the LDC, however, the PUC clearly retains the jurisdiction to reinstate more restrictive price regulation for LDC gas sales.

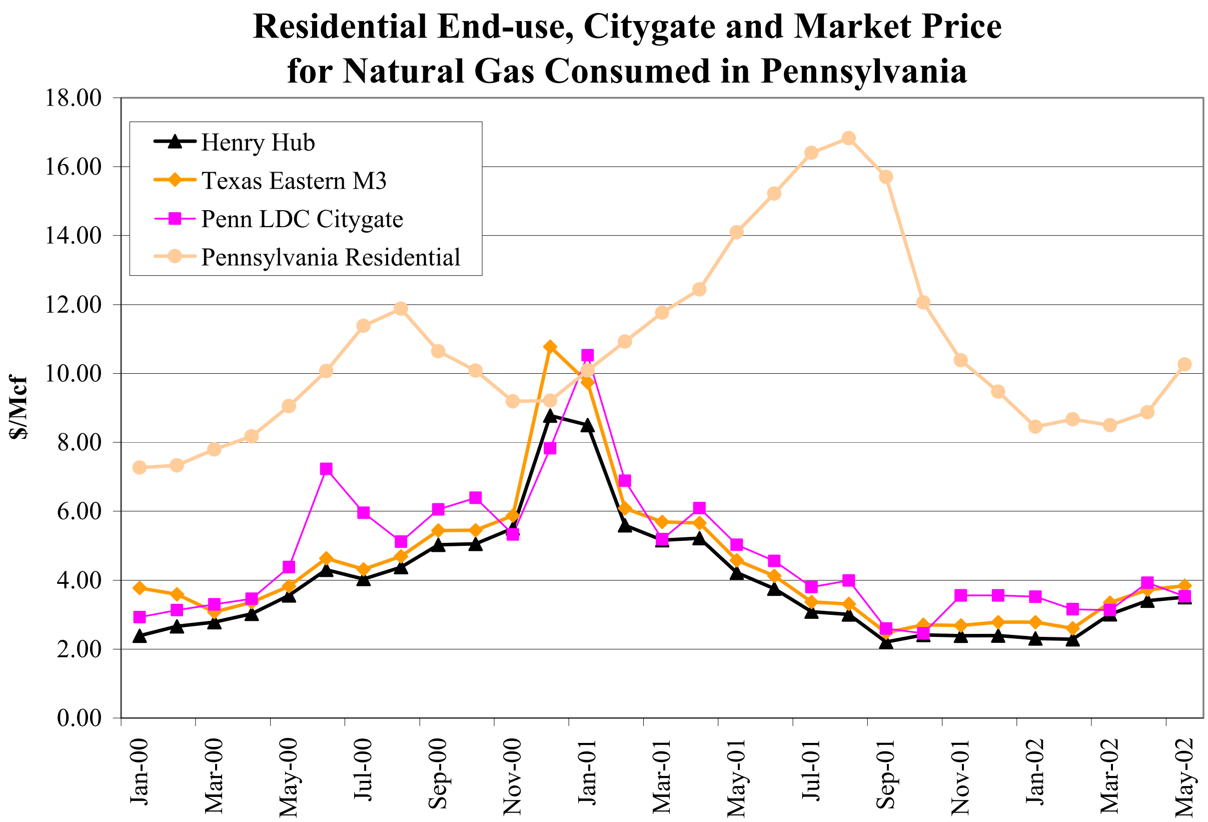
Retail customers in many states have the ability to choose a gas supplier other than the LDC. In these instances, the price of the gas sold by the marketer is not subject to price regulation although the costs of the delivery services provided by the utility remain regulated.

Figure 1-7 presents a time series for natural gas prices at different points along the supply chain for the Pennsylvania residential gas market. The chart illustrates the complexity in evaluating

[4] Gathering systems aggregate natural gas from a number of different wells and fields, and treat the natural gas to meet pipeline natural gas quality standards, prior to delivery into the pipeline system.

gas price information. There are a number of features in the price behavior that do not make intuitive sense. First, in each of the two years shown, the residential gas price is highest in the summer months despite the fact that the prices in the wholesale market were much higher in the winter. Second, during December 2000 and January 2001, the retail price for gas to residential customers was actually below the wholesale price despite the significant costs associated with delivering the gas to the customer.

Figure 1-7



The structure of most retail gas rates regulated by the state PUC creates these anomalies. Residential customers in Pennsylvania, just as in most states, pay rates that have at least two components. The first component is a monthly customer charge. These customer charges can vary from a few dollars per month to $12 dollars per month depending upon the utility. The second part of the rate is a usage charge that applies a charge on each unit of gas actually consumed.[5] With a portion of the rate fixed by the customer charge, all other things equal, the more a customer uses, the lower the average price per MMBtu. In the summer, when there is no heating load, the residential price (expressed in $ per MMBtu) is increased significantly by the customer charge, creating the unusual pattern in prices even though total residential ***bills*** decline substantially during the summer.

5 Some utilities and jurisdictions apply a block structure to the usage charge, charging one unit rate for each therm consumed up to a limit and a different unit rate charge for all units above the limit.

In addition, residential gas prices are affected by the structure of gas cost recovery built into most PUC regulated rates. Pennsylvania, as in many jurisdictions, approves a per unit charge that is intended to recover the utility's actual gas costs. To the extent that the actual costs are less than the approved rate, the difference is returned to the customers through a reduction in the allowed per unit charge for gas sold in a subsequent period. But if the actual gas costs incurred by the utility is greater than the approved rate, the under recovered balance is collected through an increase in the per unit rate charge in the future. As a result, the increase in Pennsylvania's residential gas prices throughout the second half of 2001 (when wholesale gas prices had declined) is attributable to the increase in wholesale prices from the winter before.

Implications of the Complexities in Defining Energy Prices

With multiple series of energy prices, often with real or perceived inconsistencies, it is no wonder that consumers, regulators and legislators can have a difficult time in interpreting energy price movements. Moreover, price volatility in a particular price series may or may not provide the appropriate price signals to the producers or consumers of energy. As discussed more fully later in this report, the absence of the efficient transfer of price signals can increase the magnitude of the price volatility events and contribute to the adverse impacts on consumers and many energy market participants.

1.2.3 Statistical Measurements of Energy Price Volatility

Measuring Energy Price Volatility

As discussed earlier, price volatility is not a precisely or easily defined term. One consequence is that there are a variety of ways of measuring price volatility, depending on the elements of volatility that are considered critical. In addition, there are two different, albeit related, points of reference when measuring volatility.

The first point of view focuses on absolute energy price levels. Much of the energy press and general press looks at volatility in terms of absolute levels of energy prices. A highly volatile market is a market in which average prices are changing rapidly in unanticipated ways, and in which next month's prices, or next year's prices, are likely to be substantially different from current prices. One typically uses absolute energy price level volatility when evaluating energy price volatility over an investment planning horizon.

The second perspective measures volatility in terms of "return", or change in price relative to the initial price. "Returns" measure volatility as a percentage change in prices, rather than in absolute prices, and can be viewed as a measure of expected return on investment, e.g., a 10 percent increase in price represents a 10 percent return on the value of the underlying asset, regardless of whether the 10 percent return represents a $0.20 increase from $2.00 per MMBtu, or a $1.00 increase from $10.00 per MMBtu. This perspective is most often associated with financial markets, and is the normal frame of reference for traders and risk managers who are concerned with short-term changes in returns. A highly volatile market is a market in which day-to-day changes in prices are very large relative to the base price. Wholesale electricity prices traditionally have been highly volatile.

The key statistical approaches for measuring volatility are summarized below for each perspective.

1) Daily Price Range: Range represents the spread in prices during a specific period. In markets with a uniform product and an open bidding process (e.g., the stock market), the range is often defined as the average spread between the bid price and the ask price during a specific time period. For markets where bid and ask prices are not typically available (such as natural gas markets for all locations with the possible exception of the NYMEX Henry Hub contract) or for markets without a uniform product, the range is typically measured as the difference between the daily high price and the daily low price. When all else is equal, and where the product is uniform, an increase in the range typically indicates an increase in volatility, and/or a decrease in liquidity. Daily price range is used in the Parkinson Measure of Volatility discussed below.

2) Standard Deviation: The standard deviation in average prices represents an absolute measure of the actual price movement over a specific period. The standard deviation represents the expected deviation from the average market price during a given period. A higher standard deviation represents greater price movement, and when looked at in absolute terms, a higher standard deviation represents greater price volatility.

3) Coefficient of Variation: The Coefficient of Variation is a relative measure of price movement, and is calculated as the standard deviation divided by the mean value. The coefficient is a useful comparative measure of price volatility for different commodities when prices are measured in different units, and with different baseline prices (e.g., electricity price volatility vs. natural gas price volatility).

4) Parkinson's Measure of Volatility: The Parkinson Measure of Volatility uses range rather than midpoint or market close data to estimate price volatility, hence provides a measure of volatility based on the difference between high and low prices within a given time period (such as a day, or over the bidweek). It is particularly useful for exchange-traded energy products where at any given moment, all trades are made at a single price. It is less useful for comparing volatility among different data series where prices may not be the same because they reflect different credit risk premiums or product differentiation. Changes in the Parkinson measure over time can be used as an indicator of changes in volatility between time periods.

   The Parkinson's Measure of Volatility is estimated using the following equation:

   $$Var(P) = (\ln(Hi) - \ln(Lo))^2/4\ln 2$$

   Where:

   Var(P) = Volatility of Prices

   Hi = Daily high price

Low = Daily low price

5) Returns: Traders and risk managers often measure volatility as a percentage change in prices, rather than in absolute prices. Measurements of volatility based on percentage changes in prices are often referred to as "returns" and reflect the expected "return" on investment in a commodity.

   $\text{Return}(_a) = \text{Price}_a/\text{Price}_{a-1}$

   Returns are calculated on a log-normal basis using the form:

   $\text{Return}(_a) = \ln(\text{Price}_a/\text{Price}_{a-1})$

   The log-normal form is used in order to create a more normal data distribution. Since prices are bounded by zero on the downside, and do not have a limit on the upside, the distribution of price data is often skewed (see discussion of skewness below) unless evaluated using a logarithmic form.

6) Annualized Returns: Returns are usually annualized in order to compare volatility of price series with different time periods (e.g., daily spot price volatility vs. monthly bidweek price volatility). For daily prices, the annualization period is the number of trading days in a year.

Other Relevant Statistical Measures

From a statistical basis, several other characteristics of the price data are important to consider when evaluating price volatility data. Since most of the statistical techniques for measuring volatility, including use of the standard deviation and coefficient of variation are best used for evaluating data with a "normal", or bell shaped distribution, statistical measures to evaluate the normality of the distribution are important to consider. These include skewness and kurtosis, as defined below.

- Skewness measures the degree of asymmetry of a distribution. If the distribution has a longer tail on one side of the distribution than the other, the distribution is skewed. Variables such as price, which have a theoretical minimum value (zero) but no theoretical maximum value, typically would be expected to have a skewed distribution. Data skewness provides a measure of the asymmetrical market impact of directionally different effects. For example, an increase in demand due to colder than normal weather will typically have a larger upward impact on natural gas price than a similar decrease in demand due to warmer than normal weather. We can observe this on an anecdotal basis by reviewing the energy market case studies presented in section four of this report. EEA's fundamental market analysis also supports this conclusion.

- Kurtosis: Kurtosis represents a measurement of the degree of peakedness of a data distribution. Often referred to as the "excess" or "excess coefficient" relative to a normal distribution, Kurtosis is a normalized form of the fourth moment of a distribution[6].

Raw price data tends to be highly skewed, although the distribution of the log of daily changes in raw price data (daily price returns) tends to be close to a normal distribution.

1.2.4 Utilization of Volatility Measures in the Energy Industry

Natural gas market participants are using the various measures of volatility in a number of different ways in attempts to limit utility and customer exposure to fluctuating prices. The following section presents examples of applications in energy markets.

Hedging and Gas Portfolio Management

Natural gas LDCs around the country are adopting gas price hedging techniques to limit price risk as part of gas portfolio management. Under the traditional cost of service model for gas utility rates, the cost of the gas and the cost of transportation storage services needed to bring the gas to the LDC Citygate are expenses that the LDC recovers directly in its rates, with no profit or earnings. Since these expenses represent a large percentage of the total cost to consumers, most state regulators have created a separate “tracker” account for these charges, most often called Cost of Gas Accounts (CGA). To the extent that the actual gas costs differ from those costs that are reflected in the rates, the positive or negative balances are accumulated in a “true-up” account and are surcharged or refunded through adjustments to the CGA in a subsequent period, These adjustment appear as a purchased gas adjustment (PGA) line item on customer bills.

The gas utility is responsible for prudently managing gas purchase costs, and recovery of gas purchase costs is generally subject to regulatory review. As a result, most LDCs hedge part of their natural gas purchases in order to reduce gas price volatility to customers and to create a portfolio of natural gas supplies likely to be deemed prudent by their regulators. Hedging may be accomplished using both physical means, such as longer-term natural gas supply contracts and natural gas storage, as well as financial hedging strategies including gas price options and collars[7].

However, hedging is not a cost-free activity. Hedging is essentially paying someone else to take the risks inherent in price volatility. In addition, while hedging can result in lower gas prices if the market prices are higher than expected, it can also result in costs higher than the market, if the market falls due to factors such as a warmer than normal winter. In cases where an LDC locks in prices that are higher than the actual market turns out to be, the LDC runs the risk that a portfolio will be “out of the market,” with subsequent cost disallowances as part of a prudence

[6] The first moment is the mean of a distribution, the second moment is the variance, and the third moment is the skewness of a distribution.

[7] A price collar is a Contract or group of contracts between a buyer and seller of a commodity whereby the buyer is assured that he will not have to pay more than some maximum price and whereby the seller is assured of receiving some minimum price.

review of gas purchase costs. As a result, most utilities try to hedge only a part of their total supply portfolio.

Optimization of Storage Assets

In the traditional natural gas market, storage has served to balance production and end-use demand, and to replace pipeline capacity. Historically, natural gas pipelines have owned most of the storage capacity directly, using it for operational purposes or contracting with LDCs for use in the LDC gas supply portfolio to meet weather sensitive load. LDCs developed and owned capacity not owned by the pipelines, using it for the same purposes. LDCs justified their investments in storage capacity to state and federal regulatory agencies as part of a reliable and presumably economic supply portfolio. and the storage costs were considered part of the supply portfolio, and were passed through to ratepayers. There was little or no incentive to use storage to arbitrage short-term gas prices, or to develop storage with the capability of maximizing its arbitrage value.

Over the past two decades, regulators and policymakers have restructured the natural gas industry from a market in which gas was purchased by a pipeline at the wellhead and resold to an LDC or other customer at the Citygate, to a vibrant commodity market. Market participants buy and sell gas at more than 50 liquid market centers throughout North America at prices that are largely determined by the supply and demand of gas at that location and by the pipeline capacity that is available to move gas between market centers. Because the demand for natural gas is affected to a large degree by weather and because weather conditions can change rapidly and unexpectedly, large and sudden shifts in gas demand can occur that create severe imbalances. Prices change to address these imbalances. Because supply and demand for gas can be quite inelastic, gas prices have become quite volatile.

With the changes in the structure of the gas markets that have taken place, storage has become an important tool for price arbitrage and hedging to manage and profit from gas price volatility. Companies can inject gas into storage when prices are low, and withdraw it from storage when prices are higher. On a seasonal basis, the arbitrage value of storage can be locked into place using futures markets to hedge the future price of the gas put into storage. Storage is a tool for price arbitrage on both a seasonal basis and a short-term (daily, weekly, or monthly) basis. As a result, the tools used in the financial markets to assess the value of options and futures markets are also used to evaluate the value of natural gas storage.

Trading “Spark Spreads” and “Crack Spreads” to Limit Risk

The deregulation and unbundling of the natural gas and power generation markets has also created an opportunity for power generators to minimize revenue risk and volatility by using futures markets to link their cost of natural gas to revenue received from power sales. The futures markets allow power generators to lock in a specific "spark spread," the difference between power sales revenues and the cost of the natural gas inputs.

Power generators can lock in a particular spark spread with several different methods:

- Generators with customers willing to sign long-term contracts can link the price of the power to a natural gas index price. In this case, the power purchaser can hedge price risk by locking in natural gas prices using the futures market.
- Alternatively, generators with customers willing to sign long-term contracts can set the price of power, and then lock in natural gas prices themselves using the futures markets.
- Generators can also arrange tolling agreements, in which the customer provides the natural gas and receives the power produced in exchange for a specified fee.

The lack of a liquid electricity futures market has inhibited the development of financial instruments directly linking natural gas and electricity price spreads.

1.2.5 Methods of Assessing Future Volatility

Recent levels of volatility in the natural gas markets have been higher than historical levels, leading to significant interest in assessing the likely trends in future volatility. There are two main approaches to assessing future volatility. In the near- to mid-term, natural gas price volatility can be projected by using “option pricing” as a measure of the market’s expectation of future volatility. In the longer term, the only currently available approach to assessing future gas price volatility is an analysis of the fundamental factors influencing natural gas market volatility based on observations of historical trends and projections of future market behavior.

Implied Future Volatility Using “Option Pricing” as a Measure of the Market’s Expectation of Future Volatility

In locations with a liquid futures and options market, the assessment of natural gas price volatility over the near- to mid-term can be accomplished by using the price of financial options as a measure of market expectations of future volatility in natural gas markets. Options are generally defined as a contract between two parties in which one party has the right, but not the obligation, to buy or sell an underlying asset. The prices of financial options are set by the market's assessment concerning the value of the right to buy or sell, which varies with the expectations concerning price volatility during the period in which the option is active.

The investment industry has expended great effort evaluating market volatility to estimate the intrinsic value of an option. The classical assessment of the market value of an option uses a series of equations initially developed by Fischer Black and Myron Scholes and later expanded by others. The Black-Scholes model estimates the value of an option, and hence can be used to determine the appropriate price that a rational investor would pay for that option. The key unknown in the Black-Scholes model is the expected standard deviation of daily returns for the asset. Since one can observe the value that the market places on a given option, one can use the Black-Scholes model to determine the intrinsic volatility of the asset. Figure 1-8 illustrates the equations in the classical Black-Scholes model.

Using the Black-Scholes model, we can evaluate how the value of an option to buy natural gas in the future changes with changes in the amount of expected volatility. Figure 1-9 shows the price behavior of an at-the-money call option with 6 months maturity as volatility[8] changes. The cost of a call option increases as volatility increases.[9]

When using the Black-Scholes Pricing Model to calculate the price of options, volatility is a key component as it is the only unknown variable. The other components - strike price, futures price, days to expiration and the risk free rate – can be determined. Traders use historical volatility to provide a basis for forecasting future volatility. Their expectations of future volatility will then drive trading behavior.

Figure 1-8
Black-Scholes Model Equations[10]

The Model:

$$C = SN(d_1) - Ke^{(-rt)}N(d_2)$$

C = Theoretical call premium

S = Current Stock price

t = time until option expiration

K = option striking price

r = risk-free interest rate

N = Cumulative standard normal distribution

e = exponential term (2.7183)

$$d_1 = \frac{\ln(S/K) + \left(r + \frac{s^2}{2}\right)t}{s\sqrt{t}}$$

$$d_2 = d_1 - s\sqrt{t}$$

s = standard deviation of stock returns

$\ln$ = natural logarithm

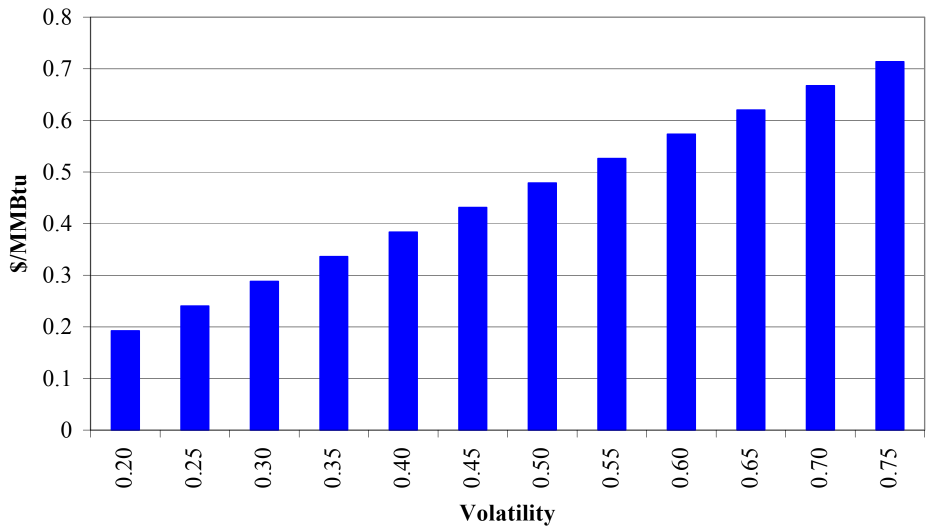
8 Where volatility is defined as the annualized standard deviation of the log of the changes in the futures price, expressed in percentage terms.

9 Assumptions: futures price = \$3.5/MMBtu; strike price = \$3.5/MMBtu;, interest rate = 5% time to maturity = 6 months.

10 Source: http://bradley.bradley.edu/arr/bsm/model.html

Figure 1-9

Impact of Volatility On Call Price
(Calculated using the Black-Scholes Pricing Model)



Another important component is implied volatility. This can be inferred from the current price of an option and is the market's forecast of future volatility. If this implied volatility seems low compared to traders' expectations, then traders will tend to buy options. Conversely, if implied volatility seems high, traders will sell options.

Figures 1-10 and 1-11 illustrate the impact of historical price volatility on the theoretical price of an at-the-money call option. Figure 1-10 shows the historical volatility, calculated as the standard deviation of the log of the changes in the futures price. This measure of volatility was then used to calculate the cost of a call option on a 6-month futures contract where the strike price is equal to the current price of the futures contract. As the graphs show, the cost of the option increases when the volatility increases.

Figure 1-11 also indicates the significance of the increase in historical volatility on hedging costs. During 1999 and the first quarter of 2000, when natural gas price volatility remained relatively low, the theoretical cost of a six-month forward option generally ranged from about $0.10 to $0.20 per MMBtu. However, when volatility started to increase in 2000, the option value of a six-months forward contract increased to as high as $0.80 per MMBtu.

Figure 1-10

Historical Volatility in the Daily Closing Price of the 6-Month Natural Gas Futures Contract

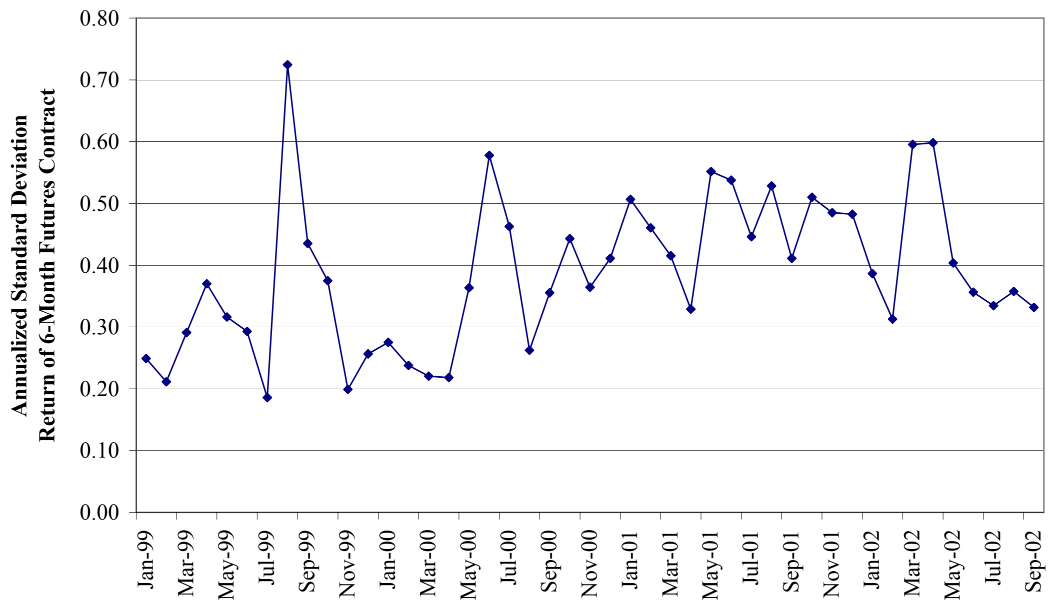
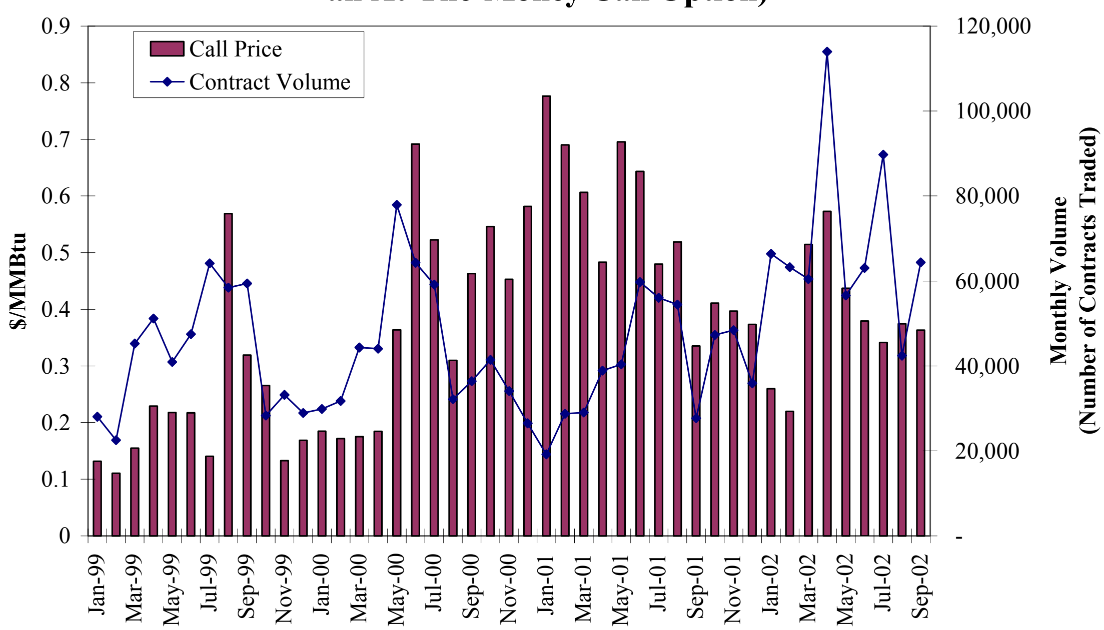


Figure 1-11

Theoretical Cost of a 6-Month Hedge on Natural Gas Prices (Based on Black-Scholes Pricing Model for an At-The-Money Call Option)



Fundamental Analysis of Historical Trends

Conceptually, price volatility is a function of daily and seasonal demand volatility, combined with supply constraints. In a tight market, changes in daily and seasonal demand are expected to have a bigger impact on prices than during periods with excess capacity in the market. This is borne out by both anecdotal evidence and statistical evaluation of the historical data.

End-Use Demand Volatility

Daily demand volatility is expected to change over time as the mix of end-use demand changes. Our analysis leads us to believe that daily demand volatility will continue to increase over time in absolute terms, due to continuing growth of weather sensitive load.

In addition, the growth in power generation load is expected to increase daily demand volatility in most regions. The majority of the new natural gas power generating stations will not operate as baseload sources of power. Instead, as marginal sources of electricity supply, they will cycle on and off, leading to large day-to-day swings in natural gas demand.

Natural Gas Supply Tightness

The impact on prices of the demand volatility inherent in the gas market depends on the overall tightness of natural gas supplies in the market. In a tight market, changes in day-to-day demand have a greater impact than in less tight markets. We have used the absolute level of market prices as a proxy for the overall tightness of the natural gas supplies to develop a statistical relationship between supply tightness and daily price volatility. The statistical analysis indicates a strong correlation between absolute natural gas prices and daily price volatility. Volatility, measured as the monthly average of daily price volatility, increases at a slightly greater than one-to-one ratio with natural gas prices. The use of regional prices as a proxy for market tightness provides an assessment of the impact of overall natural gas availability in the North American market, as well as an assessment of regional supply constraints such as pipeline capacity and storage inventory levels.

1.3
ENERGY PRICE FUNDAMENTALS

1.3.1 Natural Gas Price Fundamentals

Recent press coverage of energy price volatility has focused primarily on disturbing allegations concerning potential market manipulation by a handful of major energy companies and on the impact of price volatility on the balance sheets of all unregulated energy firms involved with electricity generation or energy trading. However, energy price volatility also plays a critical and often overlooked role contributing to the efficient operation of energy markets.

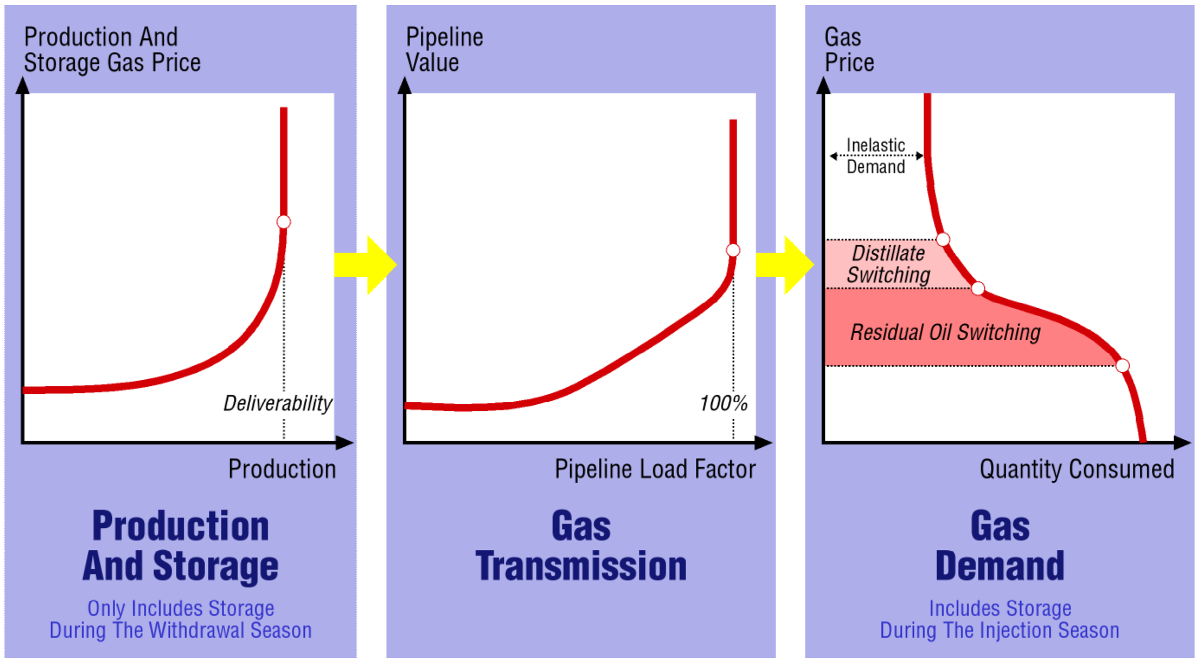
In an efficient market, prices adjust to correct imbalances of supply and demand. The magnitude of the change in prices is determined by the size of the imbalance and the willingness and ability of producers and consumers to respond to relieve the imbalance. This is true for both the short-term and the long-term.

- In the short-term, the demand for natural gas and electricity is affected to a large degree by weather. Because weather conditions can change rapidly and unexpectedly, large and sudden shifts in service demand can occur, which create significant imbalances.
- In the longer-term, prices signal the need to develop new resources and provide the incentive required to stimulate free market investment in new resources. The long-term demand response to higher prices is investment in more efficient equipment, fuel switching and energy substitutes.

Figure 1-12 illustrates the fundamental economic relationships among supply, price, and demand that act to equilibrate natural gas markets. In all sections of the market, price response differs depending on the situation in the market. Production and storage become very price inelastic as they approach the limits on deliverability. Pipeline transmission value also becomes very price inelastic as capacity limits are reached. Once capacity is reached, available supply changes very little, regardless of price. As a result, once capacity is reached, the market equilibrates primarily based on demand price response. Demand price response differs depending on natural gas price levels relative to other fuels. Natural gas demand is much more price elastic when gas prices are competitive with residual fuel oil and/or distillate fuel oil. When gas prices exceed the point at which available dual-fired capacity has switched from natural gas to oil, price elasticity drops, and it takes a significant increase in price to produce a small reduction in demand. When gas prices are below the point at which most dual-fired capacity has switched from oil to natural gas, a large decrease in price would be necessary to stimulate additional demand.

Figure 1-12

Gas Price Fundamentals: Gas Quantity and Price Equilibrium



Producer Response to Price Changes

In the natural gas market, producers have limited ability to respond quickly to changing price conditions. Under all but the lowest price conditions, producers market a very high percentage of their total wellhead gas deliverability. Deliverability increases require new drilling activity, which takes three to nine months to affect available supplies significantly. As a result, near-term wellhead production is generally quite inelastic. When prices increase, significant increases in production occur only after the substantial lead time associated with new resource development. When prices decrease, production can be shut-in. However, well shut-ins tend to occur only at very low prices. Natural gas and oil production are very up-front capital intensive, with relatively low marginal lifting costs. Even at low prices, most wells remain economic to operate, as marginal revenues will exceed marginal lifting costs for all but the least economic wells. The positive cash flow provides a strong incentive to continue to produce even when prices are much lower than expected.

In the longer term, an increase in expected prices provides the incentive needed to elicit investment in new supply. Natural gas and oil resources have a planning horizon of one to three years for resources in existing onshore and shallow offshore fields, and up to a ten-year horizon for frontier resources such as Arctic gas. In addition, investment cash flow is determined by the life of the producing asset, which can be from three to twenty years. Price expectations over this extended time frame will determine investment in new production.

Natural Gas Storage Response to Price Change

Unlike electricity, natural gas can be stored economically. As a result, storage injection and withdrawal behavior act to moderate gas price volatility to a certain extent. However, a number of factors other than economic price arbitrage impact injection and withdrawal behavior. Most LDCs in cold weather climates rely on storage to meet winter season and peakday loads. The LDC gas supply plan relies on target levels of storage at different points in the season. Moreover, tariff penalties and price ratchets based on storage inventory levels can limit the flexibility needed to optimize storage economically by creating a price penalty for storage activity outside of set parameters. Nevertheless, implementation of storage management programs and the development of high-deliverability storage provide a significant physical hedge – and actually serve to mitigate daily and seasonal price volatility.

Infrastructure Response to Price Changes

Energy infrastructure constraints, particularly of natural gas pipeline capacity, and electricity generation and transmission capacity constraints, appear to be one of the key causes of recent price volatility. In the last several years, both California and New York City have experienced periods during which both electricity and natural gas demand have exceeded the available power generation capacity and natural gas pipeline capacity. When use of these physical assets approaches capacity, prices tend to increase, sometimes increasing very rapidly in reflection of scarcity rents associated with the assets. Infrastructure constraints can lead to both short-term price volatility, when demand exceeds capacity due to short-term factors such as weather, and long-term price volatility, when capacity fails to increase with demand growth or (in the case of some natural gas pipelines) natural gas production capacity.

The scarcity rents captured by existing holders of capacity provide a critical incentive to encourage additional investment in new capacity. This is a particularly important point in a deregulated market, in which return on (and of) investments in natural gas pipelines and power generation capacity is no longer guaranteed via regulated rates of return.

Consumer Response to Price Changes

Consumers' responses to price changes vary by type of customer and application. In the short-term, traditional residential and commercial gas customers show very little price elasticity. These customers adjust their demand principally in response to external factors such as weather and economic activity[11]. Thus, they provide little in the way of short-term demand response, and changes in gas prices to these customers results principally in a transfer.[12]

[11] Under very high gas price conditions, there is a limited response due to thermostat turn-back or other conservation measures. However, these changes are slow in coming because consumers don't immediately see the higher prices due to billing cycles and the lag in utility rates.

[12] The same can be said for the response in electricity demand to changes in electricity prices. The only recent instance indicating significant demand response occurred in California, where residential and commercial sector demand was reduced by an estimated 5 to 7 percent. However, the demand reduction was a combination of the

Large industrial and power generation customers with dual-fuel capability[13] can and do respond to price changes by switching fuel sources based upon the relationship between the gas price and the alternative fuel price (generally distillate or residual fuel oil).[14] However, the overall price elasticity of gas demand declines significantly once all of the easily switched customers are "off gas".

Other than fuel switching, the industrial sector's response to increasing gas prices is to cut consumption by reducing output and to implement process changes to improve energy efficiency. However, because of the general economic imperative to improve profits, most energy-intensive industries have already taken the "easy" actions to reduce energy consumption. Most significant changes take weeks, months, or years to accomplish and may involve replacing equipment. Moreover, once taken, these actions often represent a demand shift because the demand reductions achieved are not usually offset by increases when gas prices fall again. For example, customers will not remove new, more efficient equipment in response to lower prices, and industrial production capacity moved to other countries in order to find lower fuel costs is unlikely to return.

As a result, the industrial sector behavioral response to short-term imbalances in the gas supply/demand balance – beyond fuel switching – is limited to changes in industrial output. Even for such gas-intensive industries as ammonia, methanol, aluminum and steel production and processing, significant demand response occurs only when prices rise to the point that the product becomes uncompetitive in the world market. For most manufacturing industries, where gas costs represent less than five percent of the gross value added of the industrial process, very large gas price increases are needed to change output significantly.

The power generation segment of the market also can and does respond to gas price changes, in this case by shifting the dispatch of generating units. When gas prices fall, gas-fired generation can displace oil or coal units. When gas prices rise, gas-fired generation can be reduced if there is additional non-gas fired capacity that is not being utilized. Unfortunately, under most market conditions, the gas capacity provides generation at the margin. It is dispatched only after virtually all other sources of capacity are utilized. As a result, power generation gas demand does not provide a significant demand response in a "tight" gas market with rising prices. Indeed, in California, when power prices exploded to record heights, power generation customers were willing to pay astronomically high gas prices, since electricity prices made it economically feasible to do so.

Changes in the California electricity market design that would have increased demand response could have reduced volatility in both electricity and gas prices.

price response and "good-citizen" behavior in response to governmental calls for action. Economic literature has yet to identify definitively the magnitude of the price response.

13 The dual-fuel segment of the gas market represents approximately 8 to 10 percent of the U.S. gas market.

14 Such fuel switching occurs so long as the alternative fuel is available and the facility has the necessary air emission permits.

1.3.2 Price Volatility

The recent volatility in gas prices – particularly the experience of the 2000-01 winter – occurred because of the tightness in gas production and the fact that the supply/demand imbalances became too large to be moderated by the behavior of customers who could easily respond to changing price conditions. As a result, large and rapid price movements occurred.

Figure 1-13 illustrates the impact of a tightening of natural gas markets on the volatility of price response to shifts in demand. As illustrated at point P1 of the "Stable Prices" box in this figure, when natural gas prices are competitive with residual fuel oil, the price elasticity of demand tends to be relatively high. At this point, sufficient energy demand switches between natural gas and fuel oil to ensure relatively stable prices. When the natural gas markets are tighter, and a significant share of the dual fuel demand has shifted to the alternate fuel, an increase in demand will lead to relatively larger increases in prices. This is reflected at point P2 in the figure. However, in the very tight markets shown at point P3, when most of the fuel switchable capacity has switched away from natural gas, an increase in demand due to weather conditions or other factors will lead to natural gas price spikes such as those observed recently in California, New York City, and nationally during the 2000/2001 winter.

At the end of 2002, in our judgement, the natural gas market is balancing at a point between P2 and P3. Most of the dual fuel load has already switched away from natural gas, but the relatively high oil prices have kept some dual fuel demand on natural gas.

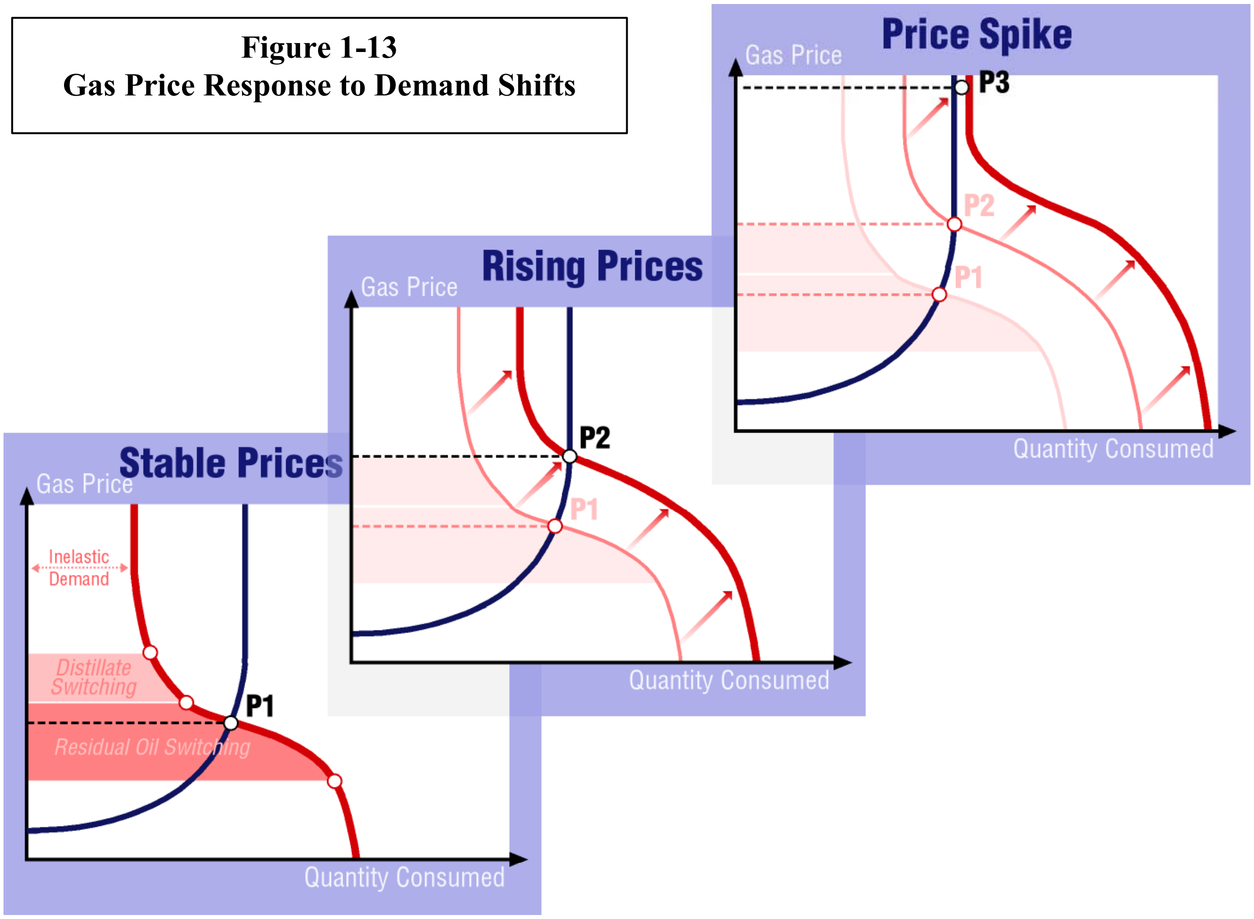
Prior to the deregulation of natural gas as a commodity, most of the market factors that led to price volatility were in existence. However, because regulations restricted price movements, regulations also had to allocate natural gas through provisions for interruptible service, and curtailment policies and procedures for firm loads. This was accomplished at the cost of restricting market growth and creating long-term gas scarcity and shortages. The restructuring of the natural gas industry removed many of the market inefficiencies created by the regulations, but also set the stage for the market volatility that we have recently seen. The challenge for the industry is to develop practical strategies to address the negative effects of volatility while preserving the consumer efficiency benefits provided by market forces.

1.3.3 Impact of Speculative Interests on Gas Prices

Colder than normal weather patterns created much of the recent short-term volatility in natural gas prices.[15] At such times, it becomes much more difficult for the collective intelligence of the market to assess market signals accurately. Transparency and the overall level of market information are reduced. This is clearly evident in historical price data, which shows wide high-low price ranges at times of rapidly increasing gas prices. In addition, large price movements draw the interest of speculators and hedge funds that view volatility as a profit opportunity. At that point, technical trading can cause the market to diverge from the fundamentals, creating additional imbalances.

[15] The impact of weather on short-term price volatility is addressed further in Appendix C.

Figure 1-13
Gas Price Response to Demand Shifts



To evaluate the impact of speculators and hedge funds on gas market prices, we have looked at the relationship between natural gas prices and non-commercial open interest in the futures markets reported by the Commodities and Futures Trading Commission. The net non-commercial open interest represents total "long" open interest contracts minus total "short" positions held by non-commercial [16] customers. This number represents a reasonable proxy for speculative positions in natural gas futures markets. Natural gas prices tend to increase when net non-commercial open interest is above zero and to decrease when net non-commercial interest is below zero.

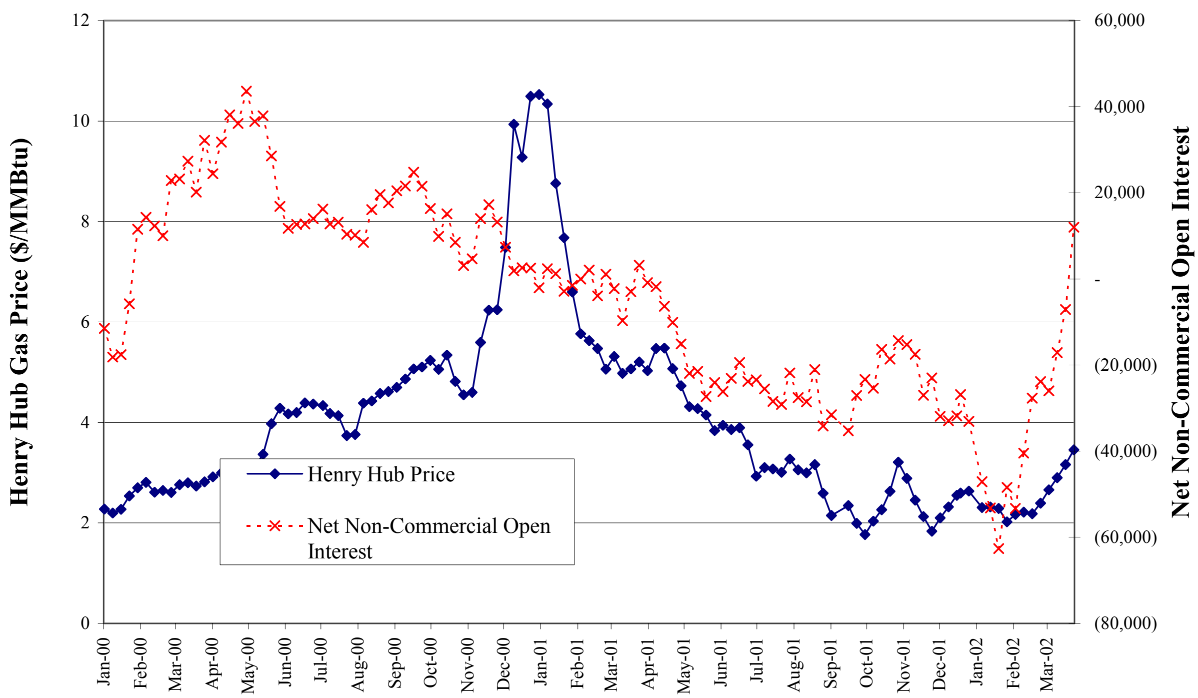
Figure 1-14 illustrates the relatively strong correlation between non-commercial open interest and Henry Hub spot prices. While this chart shows an obvious relationship over a portion of the time period only, a statistical analysis of the factors driving natural gas prices indicates a strong correlation between net non-commercial open interest and natural gas prices over the entire analysis time frame. The regression model used for the analysis included demand, capacity utilization, storage activity, and net non-commercial open interest, with highly significant results. Based on those results, we estimate that from 1997 through the first quarter of 2002, each increment of 10,000 non-commercial open interest resulted in an increase in gas prices of

[16] Excludes producers and end users.

$0.057. This relationship suggests that non-commercial open interest tends to accentuate changes in natural gas prices.

Figure 1-14

Henry Hub Price vs. Gas Futures Non-Commercial Open Interest



1.4
ENERGY PRICE VOLATILITY CASE STUDIES

Energy price volatility is currently a topic of significant interest to energy consumers, producers, public interest groups, regulators, and local and national governments due to the California energy crisis, as well as recent volatility in natural gas and electricity prices. While these two issues have dominated the press and public awareness, there have been several cases of localized shortages and price spikes in natural gas, fuel oil and electricity markets that illuminate general energy volatility issues, and help highlight key issues related to energy price volatility.

We have prepared short case studies for two high profile cases, as well as several other important occurrences, to identify the causes and effects of various energy crises over the last five years. In each case, we identify the underlying causes and discuss impacts. These case studies are summarized below.

1. North American Natural Gas Market -- April 2000 through March 2001. Weather patterns, limited natural gas deliverability caused by inadequate production infrastructure, and lags in production response resulted in dramatic increases in North American natural gas market prices. This event had a pervasive impact on the gas industry and highlighted two patterns of behavior: the degree of volatility of prices in an extremely tight market, and the sensitivity of price to demand increases when dual-fuel customers have already switched away from gas.
2. California Electricity and Gas Market -- May 2000 through May 2001. Regional temperature and precipitation patterns, inadequate power generation capacity and natural gas pipeline capacity, inadequate regulatory structures and alleged market manipulation created an energy market meltdown. This case study shows the interaction of electricity and gas prices in a constrained market. It also shows the impact of environmental regulations such as the NO_x allowance market and operating hour restrictions, on supply.
3. Alberta Natural Gas Market -- Pre-Alliance through TransCanada Capacity Restrictions. Volatility in Alberta gas markets reflects the impact of pipeline infrastructure constraints and surpluses, including that of lumpy investments. This case demonstrates the influence of pipeline capacity availability in production areas, where localized effects, such as depressed prices, distort drilling decisions and reduce supply development.
4. Midwest Electricity Market -- Summer 1999. In this situation hotter than normal weather, combined with inadequate peak generation capacity, caused a spike in electricity prices in the Midwest. The case shows that consumer electricity demand is nearly perfectly inelastic with respect to wholesale prices since consumers don’t see price movements and there is little ability to bid demand response. The case also shows a supply response in the following years that resulted in excess capacity and under-recovery of investment (boom-bust cycle).
5. Northeast Distillate Oil Market -- Winter 1999. Extremely cold weather, combined with unusually low natural gas inventory and storage levels, created distillate oil supply shortages in the Northeast during the winter of 1999. This case illustrates the importance of storage

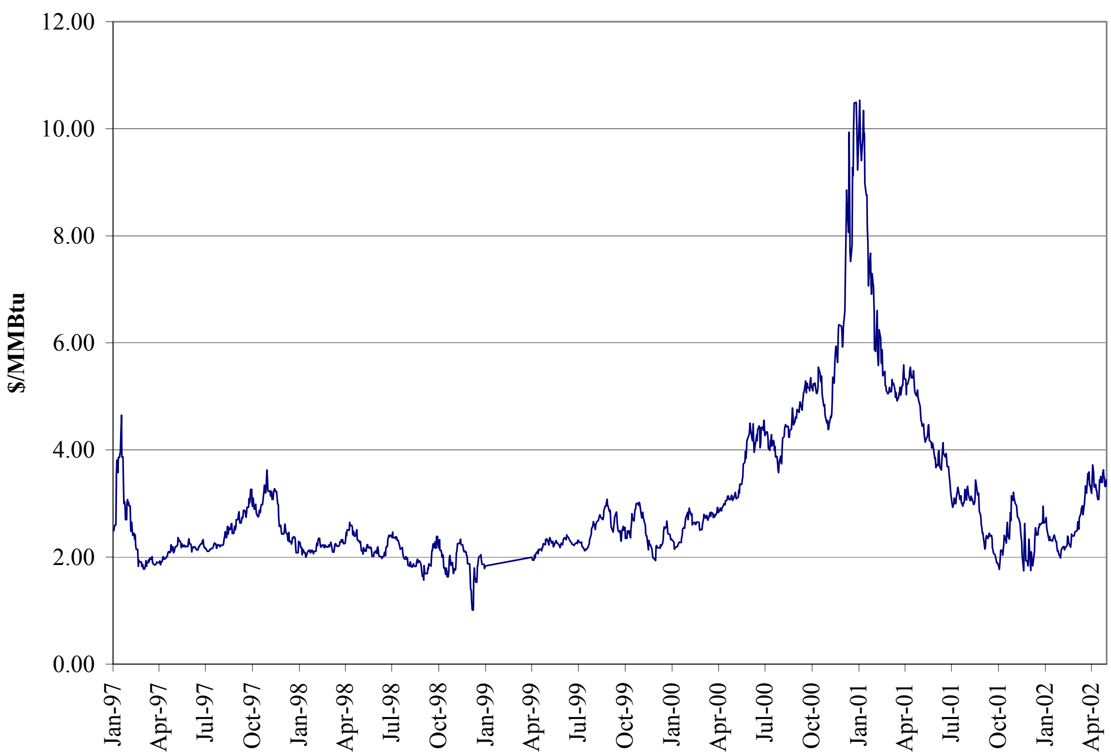
and the interaction between gas and oil inventories, including the role of industrial dual-fuel capability in mitigating price volatility in the entire energy market.

6. New York Gas and Electricity Prices -- July/August 2002: Much hotter than normal weather and constraints in power generation capacity, electricity transmission and natural gas pipelines, combined with shifting summer/winter gas load patterns and daily load fluctuations to result in substantial price spikes in the electricity and natural gas markets. The case shows the changing nature of gas flows driven by increasing natural gas-powered generation and tighter pipeline capacity constraints. It poses the question, “Who is going to build year-round capacity for peak day demand?” It also illustrates the importance of dual-fuel, high deliverability storage and inventory control, and the impact of environmental regulation on the gas and oil markets.

1.4.1 North American Natural Gas Markets 2000 - 2002

U.S. natural gas prices have been on a rollercoaster ride for the last several years, and short-term forecasts indicate that the ride is expected to continue. The Henry Hub prices shown in Figure 1-15 indicate the extent of the price swings over the last five years.

Figure 1-15
U.S. Natural Gas Market Prices at Henry Hub



The swings in price have had significant impacts on all elements of the natural gas market, from producers to end-users.

Causes of the Natural Gas Price Rise

To understand the current situation, it is useful to start much further back. A natural gas supply "bubble" developed in the early to mid-1980s as gas consumption collapsed and productive capacity for natural gas increased[17]. During this 5-year period, gas consumption decreased by 20 percent or 4Tcf, with the largest decline occurring in the industrial sector. Poor economic conditions characterized by stagflation decreased the U.S. industrial base and industrial gas demand along with it. Relatively high gas prices, attributed to the complex price environment created by the Natural Gas Policy Act of 1978, further dampened demand by discouraging the use of natural gas. On the supply side, productive capacity grew as a result of historically high drilling levels in response to high gas and oil prices.

In 1986, the controlled price environment was transformed into a competitive market in which the balance between supply and demand sets the price for natural gas. The supply bubble continued during this period, helping to keep gas prices flat at the relatively low level of $2.00/MMBtu.

Gas demand grew steadily due to the thriving economy and rapid growth of gas-fired cogeneration. However, gas-directed drilling activity declined along with oil and gas prices. Low prices provided a financial disincentive for developing large volumes of new gas resources. As a result, gas productive capacity remained relatively flat during the period. Even as consumers benefited from the low price and loose supply environment, a slow deflation of the gas bubble went unnoticed. The unfortunate effect of this deflation would soon become apparent.

The intermittent spikes in gas price that occurred during 1996 and 1997 were signals that the gas bubble had diminished, and a preview of the gas price spikes about to occur. However, it wasn't until early 2000 that gas prices started increasing on a sustained basis. Before this period, a number of events had kept gas prices in check, thus masking the tightness between supply and demand. First, warmer than normal winter weather reduced demand in the weather-sensitive residential and commercial sectors. Two of the warmest winters in the last 100 years occurred during this period. Second, the 1998 Asian economic crisis reduced U.S. industrial production, hurting industrial gas consumption. The growth in gas-fired power generation to satisfy rising electricity demand was insufficient to offset the declines in gas demand in the residential, commercial, and industrial sectors during this period.

The third factor that kept gas prices in check was the oil price collapse in 1998-99 triggered by the decline in Asian oil consumption. Since the primary alternative fuels for large natural gas consumers in the industrial and power sectors are residual fuel oil and distillate oil, the prices of those products act as backstop prices for natural gas. Low oil price during this period thus helped create a "lid" on gas prices.

Productive capacity for natural gas declined significantly during this period. The collapsing oil prices directly discouraged oil well drilling, and the gas production associated with oil

[17] Productive capacity for natural gas, often referred to as deliverability, is the maximum production physically possible given the current set of production tools and technologies.

production declined.[18] The low oil prices also caused a "cashflow crunch" for producers, decreasing the amount of capital available for new projects. In response, gas-directed drilling activity and productive capacity from gas wells declined. In addition, the low natural gas prices during the period failed to stimulate the additional producer investment needed to offset these declines. The already tight supply/demand balance was further tightened, but remained masked by reduced consumption.

During the 2000 - 2001 period, it became apparent that the balance between supply and demand was very tight. High demand due to colder than normal weather and the growth in power generation demand resulted in a historic run-up in natural gas prices. Several events triggered this run-up. First, oil prices started to rise due to an imbalance between global supply and demand as the Asian economies came back to life. The higher oil prices set a higher backstop price for natural gas. Hot weather in the Southwest and reduced hydroelectric generation pressed additional gas-fired electric generation into service, spurring gas consumption. Resumed growth of gas consumption in the industrial sector was another contributor.

The impact of the declining productive capacity for natural gas due to low drilling activity in 1998-99 soon became apparent. Beginning in mid-2000, gas prices started to rise, with prices increasing from $2.00 per MMBtu at the start of the year to $5 per MMBtu in the fall. Much colder than normal early winter weather brought prices of $9 per MMBtu in late December and early January. Prices moderated back into the $5 to $6 per MMBtu range throughout much of the country as a result of unseasonably warm weather, and then continued to fall back to the mid-$2 per MMBtu range by early 2002.

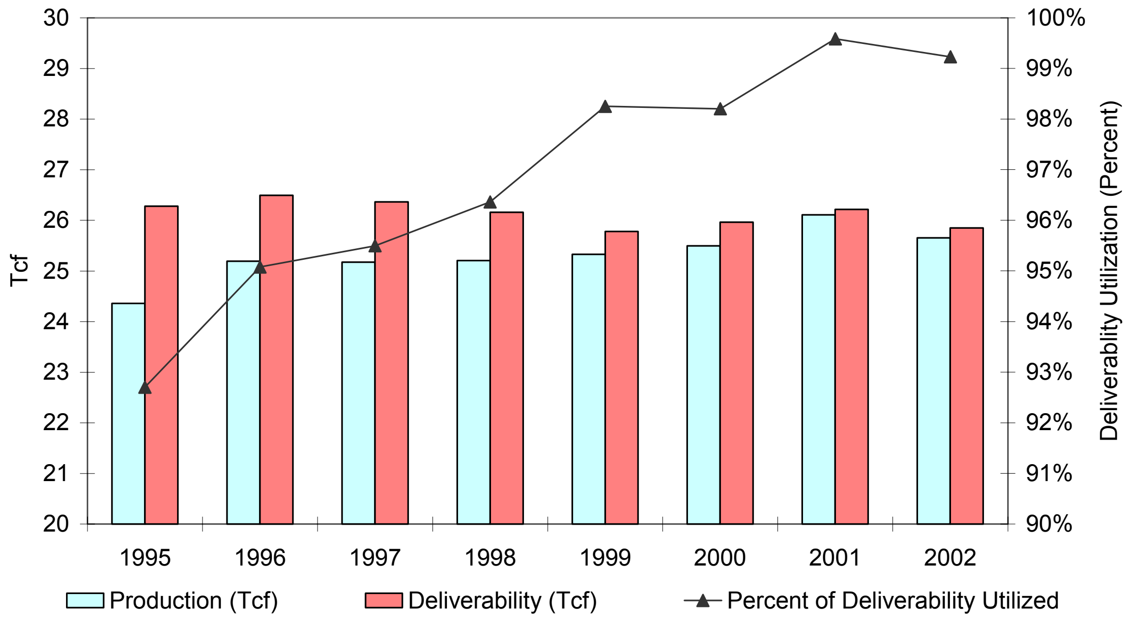
During the high price period, there was a significant amount of demand shed as a result of slowing industrial activity and the overall slowing of the economy. We estimate that plant shutdowns or curtailments in industrial activity accounted for a decline of 2 Bcfd (about 8 percent) in industrial gas demand. There is strong evidence that feedstock and energy intensive activities, such as ammonia and methanol production and metals fabrication, were hit hardest. We also estimate that gas-to-oil switching in the industrial and power generation sectors accounted for an additional 3 to 4 Bcfd "loss" in gas load.

Another key response was electricity demand lost as a result of declining industrial activity and the overall slowing of the economy. The industrial sector accounts for roughly one-third of total electricity consumption and we estimate that electricity demand in the sector decreased by about 7 percent, consistent with natural gas declines. Hence, we expect that growth of electricity use has stalled, at least temporarily. This has helped to reduce some gas use that would have otherwise been necessary in the power-generating sector.

The high gas prices in 2001 also stimulated significant drilling activity, leading to growing productive capacity for natural gas between 1999 and 2001, as shown in Figure 1-16. The combination of load shedding due to high prices and the economic slowdown, relatively warm weather during the 2001/2002 winter, and the initial growth in drilling, resulted in a year-long decline in prices.

[18] Currently, about 14 percent of U.S. natural gas production is gas produced along with oil, commonly referred to as associated gas production.

Figure 1-16
North America Natural Gas Production vs. Deliverability



Source: EEA August 2002 Monthly Gas Update.

While gas-directed drilling activity increased significantly in response to high gas prices in 2000 and 2001, the lag between rig activity and changes in productive capacity meant that its full impact was not immediately felt. Hence, the results of drilling investments made when Henry Hub prices were above $6.00 per MMBtu were not reflected in additional production capability until prices had fallen back below $3.00 per MMBtu. The relatively abrupt decline in prices effectively halted drilling activity, with active drilling rigs in the U.S. declining from 1,278 in July 2001 to 750 in April 2002. This led to the decline in estimated 2002 natural gas deliverability.

Impacts On Market Participants

The natural gas market price run-up and drop-off that occurred during 2000/2001 is having several critical long-term impacts on the development of future natural gas markets, as described in the following paragraphs.

First, the price collapse that occurred after the run-up has made natural gas producers more conservative in making investment decisions. Due to the current tight supply/demand balance and relatively high natural gas prices, substantial investment in new productive capacity is likely required in order to avoid another dramatic price fly-up in the next couple of years. However, producers are much more risk-averse now than they were two years ago, and do not appear to be increasing investment as rapidly as they have in the past. Gas price volatility has increased the risk of new investments in natural gas-fired power generation, contributing to the increased cost and reduced availability of financing for new gas-fired generation capacity. This behavior, while reducing risk for individual producers, curtails the development of supply and appears likely to exacerbate natural gas price volatility in the next few years.

Second, the gas price volatility experienced during this period focused renewed attention on the trend toward a deregulated market. The collapse of Enron and the liquidity troubles being experienced by other natural gas trading firms have changed the fundamental market outlook for a significant share of the natural gas transportation, distribution, and marketing industry. These events have resulted in substantial reductions in companies' willingness to make long-term investments in either physical assets, such as pipelines, or organizational assets, such as trading systems, new product development, and staff familiar with the deregulated environment.

Before the price run-ups, companies seeking to please Wall Street were divesting regulated utility assets and focusing on deregulated activities, investments, and opportunities. After the price run-up and the collapse of the corporate credit markets, the same companies are retrenching, shedding unregulated divisions and assets, and focusing and promoting their regulated businesses.

The Enron collapse and other revelations of apparent corporate improprieties, such as wash trading, have also attracted renewed attention from state and national regulators on both natural gas and electricity energy issues.

The recent volatility in gas prices – particularly the experience of the 2000-01 winter – occurred because of the tightness in gas production and the fact that the supply/demand imbalances became too large to be moderated by the behavior of customers who could easily respond to changing price conditions. As a result, large and rapid price movement occurred. Much of the short-term volatility was created by colder than normal weather patterns. At such times, it becomes much more difficult for the collective intelligence of the "market" to accurately assess market signals, and transparency and market information are reduced. This is clearly evident in the historical price data, which shows wide surveyed high-low price ranges at times of rapidly increasing gas prices. In addition, large price movements draw the interest of speculators and hedge funds that see volatility as a profit opportunity. At that point, technical trading can cause the market to diverge from the fundamentals, creating additional imbalances.

Outlook for the Future

Figure 1-16 also indicates that the supply balance remains extremely tight, with 2002 natural gas deliverability utilization of above 99 percent. We expect that gas price volatility will continue due to a supply/demand balance that remains tighter than the balance over the past decade. There will likely be periods (primarily when weather conditions differ significantly from normal conditions) during which gas prices will spike up well beyond the price of competing oil product prices. These periods will offer significant price arbitrage opportunities for traders and marketers. They will also make it more difficult for large industrial purchasers of gas to gauge the true value of the commodity.

We don't expect the pressure on the demand side to abate any time soon. Winter weather that is closer to normal than that experienced in recent years will increase residential and commercial gas consumption well above the consumption levels exhibited during those warmer than normal winters. Industrial gas consumption is likely to continue to grow as, and when, the economy continues to grow. And, continued growth in electricity demand will spur the need for new gas-fired generating capability.

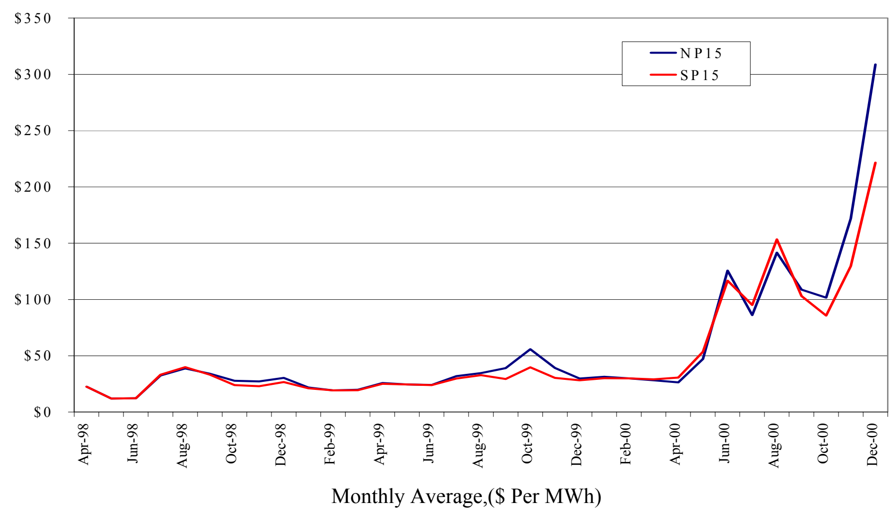
Hence, the supply/demand balance is likely to remain very tight over the next few years. Gas prices could be extremely high and volatile, depending on weather.

1.4.2 California Electricity and Gas Market May 2000 through May 2001

Price Behavior – California Electricity and Gas Market

Wholesale electricity prices traded on the California Power Exchange (CalPX) began increasing dramatically in June 2000 (see Figure 1-17). By December 2000, wholesale prices on the CalPX averaged $308.75 per MWh for Northern California and $221.61 per MWh for Southern California, compared to $29.75 and $28.33 per MWH respectively for December of 1999.

Figure 1-17
Record of Day-Ahead Prices in the CalPX



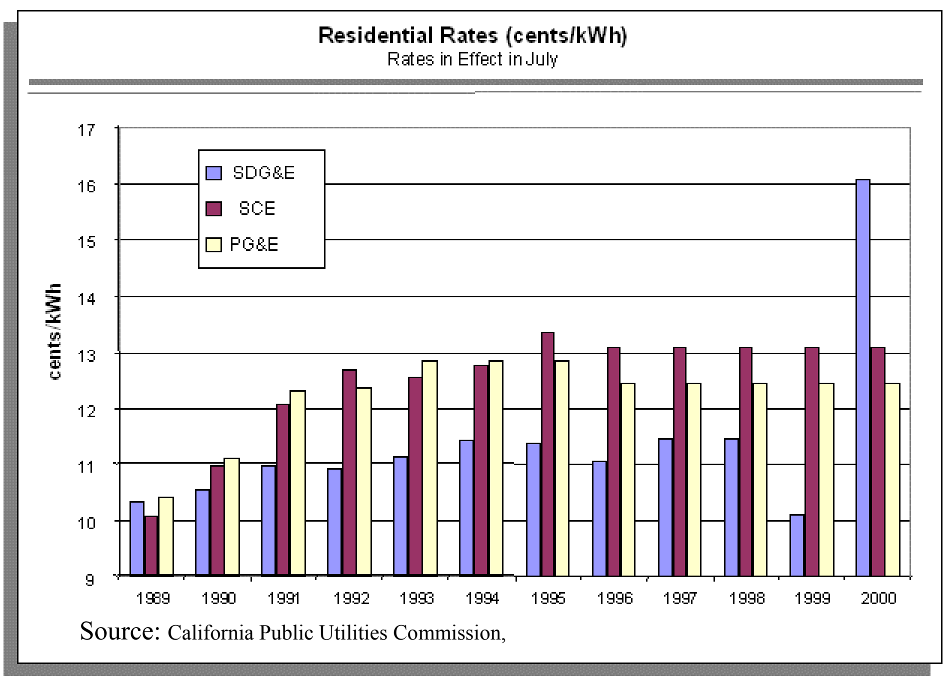
NP15 means Northern California and PG&E
SP15 means Southern California and Southern California Edison
Source: California Energy Commission

In 1996 and 1997, California restructured its electricity industry based on Assembly Bill 1980 passed by the state legislature. The state's independent system operator (ISO) took over operational control of the utility-owned transmission system. The three investor-owned utilities in California -- Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric Company (SDG&E) -- began purchasing all of the energy needed to serve their retail customers through the day-ahead or day-of spot markets. In fact, these three utilities were required to make all their purchases through the spot exchange and were precluded from entering into long-term energy supply contracts. Regulators froze each utility's retail rates by statute, at what regulators then perceived as an artificially high rate, for a time period sufficient to recover certain stranded generation costs. This retail rate freeze was scheduled to end when these capital costs had been recovered or at the end of 2001, whichever came first.

The rate freeze ended for SDG&E in mid-1999 but remained in place for PG&E and SCE. This resulted in a temporary spike in retail electricity prices for SDG&E customers, as the company immediately passed on the high cost of wholesale electricity to consumers. Residential rates increased to $0.16 per kWh, an increase of $0.05 per kWh from July 1999. SDG&E's rates for June 2000 reached two times the national average for residential consumers, as shown in Figure 1-18. Finally, the California legislature imposed a ceiling of $0.065 per kWh on the electricity bills of SDG&E customers.

The retail customers of PG&E and SCE were still under price caps and therefore insulated from the price increase. However, the market was setting the price of wholesale power purchased by the companies. The imbalance between the wholesale and retail price of power led to the bankruptcy of these two large utilities. In addition, demand for power exceeded available capacity, leading to rolling blackouts on several days in the summer of 2000.

Figure 1-18
California Residential Electricity Rates in Effect in July 2000



Source: California Public Utilities Commission,

Factors That Caused the Price Spike

The essence of the California crisis was insufficient energy infrastructure to satisfy energy demand on both the electricity and natural gas sides of the equation. Energy demand was much higher than anticipated due to a confluence of weather events across the entire region. National natural gas prices and California environmental regulations exacerbated the price spikes. In addition, the California regulatory structure proved inadequate during periods of supply shortage. Retail price caps eliminated market incentives to reduce energy consumption, leaving moral suasion and rolling blackouts as the only effective methods of balancing demand and supply.

There are also allegations that certain companies withheld both natural gas pipeline capacity and power generation capacity from the market during certain key periods. The California PUC has published numerous reports on this issue. Recently, FERC Administrative Law Judge Wagner concluded that the El Paso Pipeline Company withheld an average of as much as 696,000 Mcf per day of natural gas pipeline capacity from the California market during the 2000/2001 heating season. FERC Staff has reported apparent withholding of power generation capacity from the market as well. If true, the withholding of both pipeline capacity and power generation capacity from the market would certainly have exacerbated the price run-ups.

1) Failure of Long-Term Energy Infrastructure to Keep Pace With Demand Growth

Following a slowdown in the early 1990s, California's economy experienced aggressive growth throughout the second half of the 1990s, resulting in a significant increase in energy demand. Electricity demand grew by 2.5 percent per year, from 231 TWh in 1995 to 262 TWh in 2000. Natural gas demand grew by 4.2 percent per year, from 1925 Bcf in 1995 to 2360 Bcf in 2000.

This growth far exceeded the national growth rates for these commodities and far exceeded growth in energy infrastructure. In the case of electricity, new power generating capacity did not keep pace with long-term electricity demand growth, and reserve margins shrank to zero. From 1995 to 2000, less than 2 GW of new capacity was added to California's generating mix, and the 2000 level was only about 2 percent above the 1995 level. California's approval process for siting new power plants is widely considered to be one of the most onerous in the U.S. and is a significant contributor to the current California's electric generating capacity shortage.

2) Extreme Weather Patterns Increased Demand for Power While Decreasing Available Supply

California's problems became apparent in early 2000, when California's hydropower supply declined by 40% due to drought conditions in California and electricity imports from the Pacific Northwest were curtailed due to drought conditions across the Columbia River basin and the rest of the western states (see Table 1-1). We estimate that 2001 hydroelectric generation in the Pacific Northwest was 119 TWh, compared to a ten-year average of 135 TWh. With the low supply of hydroelectric generation, electricity imports to California declined to 26 TWh from a five-year average of 50 TWh. This resulted in inadequate generating capacity being available during peak demand periods.

To meet demand for power, California relies on 7 to 11 GW of out-of-state generation capability during peak periods. When power imports from the Pacific Northwest fell below normal levels, California power producers pressed marginal units into service to meet base and intermediate load requirements, and were then unable to meet peaking requirements during certain periods. It is interesting to note that the larger than normal hydroelectric generation, made possible by wetter than normal weather in 1996 and 1997, masked the declining reserve margin for generating capacity in California.

Table 1-1
California Electricity Generation (GWh)

Californa Electricity Generation
(GWh)

	1997	1998	1999	2000	2001
Total Generation:	***255,080***	***276,412***	***275,803***	***280,496***	***265,059***
Hydroelectric	41,400	48,757	41,627	42,053	25,005
Nuclear	37,267	41,715	40,419	43,533	33,294
Coal	27,114	34,537	36,327	36,804	27,636
Oil	143	123	55	449	1,328
Gas	74,341	82,052	84,703	106,878	113,569
Geothermal	11,950	12,554	13,251	13,456	13,619
Other	10,146	9,111	9,934	10,550	9,840
Energy Imports:					
Pacific Northwest	25,204	19,428	26,051	18,777	6,826
Pacific Southwest	27,517	28,135	23,436	7,997	33,941

Source: California Energy Commission

In addition, higher than expected temperatures increased demand during the summer of 2000. As a result, energy consumption and average daily loads during the summer of 2000 grew rapidly compared with the same period in 1999. Growth in average daily peak loads was higher than the previous year, with an 11% in increase in May and a 13% increase in June versus the same period the year before.

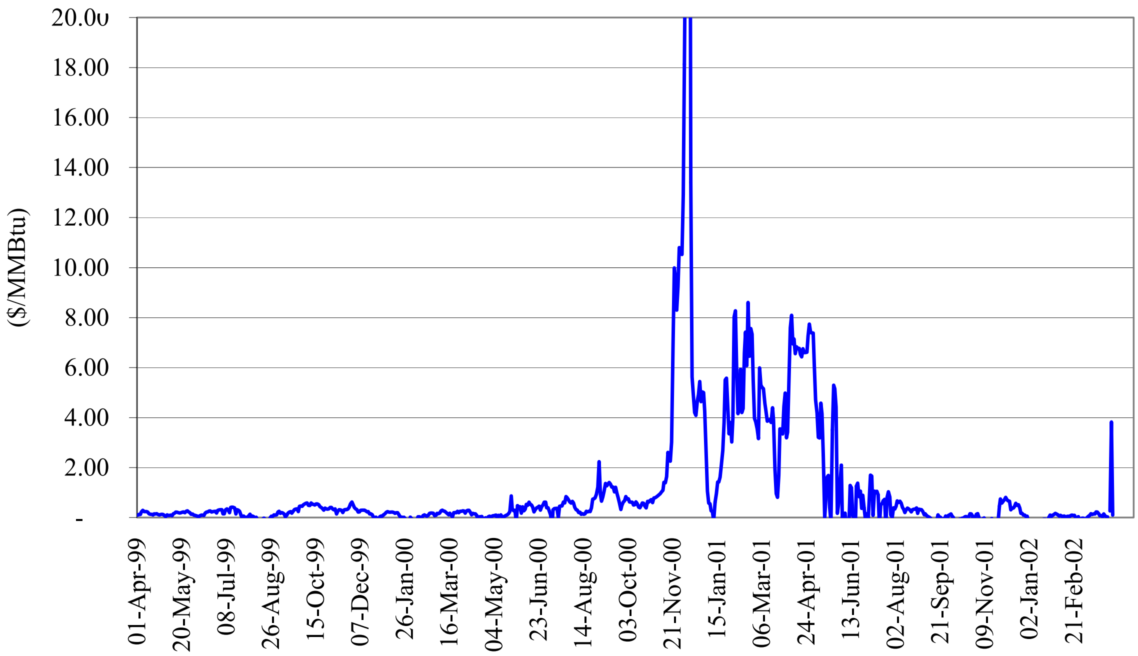
3) Higher National Gas Prices

Many of the marginal generators that were called on to satisfy California electricity demand are old oil-gas steam units located in the state. Largely due to environmental reasons, the vast majority of these units burn gas. California gas demand has jumped significantly since 2000 as a result of the increased use of these units. We estimate that gas demand for generation of electricity sold to the grid was 700 Bcf, well above the five-year average of 350 Bcf. Nationally, gas prices quadrupled between December 1999 and December 2000, from $2.35 per MMBtu to $8.50 per MMBtu.

4) Natural Gas Pipeline Constraints

The extra gas load on the California system exposed constraints on gas transportation services that became apparent in the form of extremely high and volatile gas prices. Prices for daily gas purchases for California started to increase well above supply-area prices late in the summer of 2000 and averaged well over $15 per MMBtu during the first quarter of 2001. Figure 1-19 illustrates the impact of the natural gas pipeline capacity constraints into the consuming regions of California by showing the basis differential between California gas prices and national gas prices measured at Henry Hub.

Figure 1-19
Natural Gas Basis From Henry Hub to California PG&E Citygate



Note: Basis peaked at $42.73 per MMBtu on December 11, 2000

The constraints on pipeline capacity into the state during the high price periods appear to have been internal to California as well as external. During December of 2000, the high prices were evident across the Pacific Northwest, as well as in California, suggesting a lack of pipeline capacity into the entire Western Region. At other times, the causes of the price spikes appear to have been related to insufficient transmission capability or lack of flexibility within the state to move gas from the interstate transmission pipelines directly to end-users. For example, we estimate that SDG&E mainline gas transmission capacity was about 600 Mmcfd at the time, of which 200 Mmcfd was normally used for core residential and commercial customers. SDG&E's line was likely full to satisfy gas demand for power generation. The lack of flexibility on intrastate transmission and the shortage of intrastate capacity, coupled with the price inelasticity of demand resulting from California consumers' limited ability to switch to alternative fuels, created the very high gas prices observed in late 2000 and early 2001.

5) Environmental Regulations Limited the Ability of Generators to Respond to Demand (NO_x allowance market and operating hours restriction)

California's requirement that generators have sufficient NO_X emissions credits before going online played an important role in the price spike. If power generators do not purchase enough credits to offset emissions before they go online, they are subject to large state-imposed fines.

Prices of NO_X emission credits increased substantially in the half year between the winter of 1999 and the summer of the following year, rising from $2 per pound to $30- $40per pound. An inefficient power plant could thus see operating cost increases of $40 to $80 per MWh ($0.04 to $0.08 per kWh). Because these power plants were the marginal producers, the increased costs had a substantial impact on the clearing price for California.

Conclusions and Implications

There are two major lessons to be learned from the California crisis. One is that lack of appropriate energy infrastructure represents a bottleneck that can lead to market shortages and ensuing price volatility. Continued economic growth and prosperity hinge on new energy infrastructure, not only in California but also throughout the U.S. Restricted access to gas resources, slow approval processes for new power plants and electric and gas transmission capability, and opposition to construction of new energy infrastructure pose serious problems for further energy development. Other areas of the country, particularly New York and Florida, could face energy shortages without new energy infrastructure. With regards to natural gas, areas that are at risk of extremely high prices, such as California, are generally far away from their sources of supply and have few transmission options.

The second is that price caps can create market shortages. High commodity prices send signals to market participants, spurring actions that ultimately lead to lower prices. A prime example is the natural gas market in 2001 and 2002, when prices dropped significantly from 2000 and 2001 highs in late December and early January. The high prices stimulated additional supply deliverability and caused industrial consumers to shed natural gas load. These rational market reactions to higher prices contributed to the decline in gas prices.

1.4.3 Alberta Natural Gas Production and Prices

Review of Alberta Gas Market Price Behavior

Alberta is a major natural gas producing region of North America, accounting for more than 20 percent of total North American natural gas production. While not widely noticed in the U.S., natural gas prices in Alberta have been more volatile than gas prices in the producing regions of the United States. Traditionally, natural gas prices in Alberta and northern British Columbia have traded at a discount to gas prices in the lower 48 states, reflecting the cost of transportation into U.S. markets. However, the magnitude of this discount has varied dramatically over time. Figure 1-20 illustrates the volatility in the relationship between Alberta gas prices and Henry

Hub prices. Most of the differences between these two price series are accounted for by the transportation basis between Alberta and U.S. markets at Chicago, as shown in Figure 1-21.

Figure 1-20
Difference Between Alberta Gas Price and Henry Hub Price

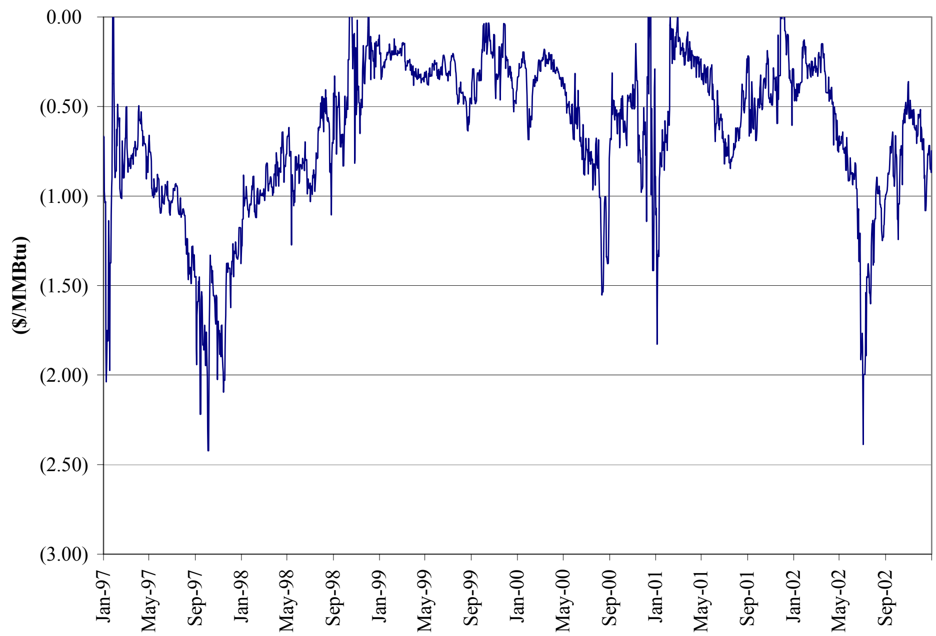
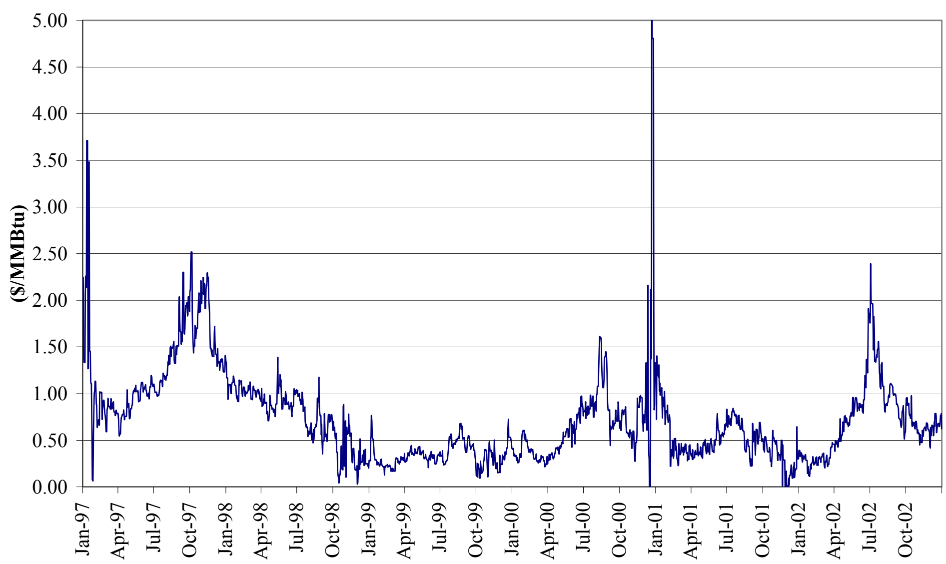


Figure 1-21
Natural Gas Pipeline Basis From Alberta to Chicago



The relatively high pipeline basis out of Alberta in the late 1990s led to the construction of the Alliance Pipeline to provide an additional capacity from Alberta to eastern U.S. markets. The completion of the Alliance Pipeline in December of 2000 increased capacity out of Alberta by about 1.7 Bcfd (15 percent), and resulted in a substantial and sustained decline in the regional basis, increasing Alberta producers' revenue. However, since April 2002, the basis from Alberta to Chicago has tripled, peaking at more than $1.50 per MMBtu in July 2002. The increase in basis has driven Alberta producer gas prices down to levels last seen prior to completion of the Alliance Pipeline.

However, pipeline flows out of Alberta on the TransCanada Pipeline (TCPL) and Alliance have not changed substantially in the last year, and current projections of production indicate only minor changes in regional natural gas deliverability. In addition, TCPL is still suffering from excess pipeline capacity, which raises a number of questions, including: 1) What is causing the change in basis? 2) Is the change in basis permanent? and 3)What is the impact of the change in basis on Alberta producers and on purchasers of Alberta natural gas?

Causes of Alberta Gas Market Behavior

The primary cause of the volatile relationship between Alberta gas prices and U.S. gas prices has been constraints on the system used to transport natural gas from the producing regions in Alberta to the end-use markets in eastern Canada and the U.S. Alberta is a major producing region, with limited pipeline options exiting the region. While Alberta and British Columbia markets are reasonably well integrated, these markets are not well integrated with other producing regions in North America. Even though significant volumes of western Canadian natural gas are consumed in western Canada, or exported to serve the California and Pacific Northwest markets, the primary market for Alberta natural gas is in eastern Canada and the Midwest and northeastern regions of the U.S. As a result, Alberta gas prices typically are set by gas prices in these regions, minus the cost of transportation.

Gas produced in Alberta typically is moved east on the TCPL system, or south on TCPL Alberta to export points in the U.S. at Kingsgate. The majority of natural gas produced in northern British Columbia is transported south on the Westcoast Pipeline into southern British Columbia markets including Vancouver, and into the Pacific Northwest via Sumas. Limited quantities move east on the NOVA system into TCPL. There is a substantial amount of natural gas storage in the producing regions of both Alberta and British Columbia.

Prior to completion of the Alliance Pipeline, TCPL provided the only pipeline route to eastern Canadian and U.S. markets, and pipeline constraints resulted in substantial swings in basis. After Alliance was brought into service in December of 2000, and winter demands in Canada and the western U.S. receded, basis from Alberta to Chicago collapsed and Alberta gas prices moved closer to parity with U.S. producer prices.

One of the key factors creating swings in basis out of Alberta is related to fundamental regulatory differences between Canada and the U.S. The TCPL interruptible transportation tariff floor rate is set at 80 percent of the firm tariff rate. When TCPL is flowing significant volumes at interruptible rates, the minimum basis on TCPL is set by this floor, which is about $0.21 per

MMBtu from Empress to Emerson and $0.59 per MMBtu from Empress to Dawn. However, there is no floor on the price of capacity on the secondary market. Hence, when TCPL customers market sufficient amounts of firm capacity on the secondary market to displace interruptible capacity, the basis falls closer to variable costs. Capacity turnback by TCPL customers in the last year has substantially reduced the amount of capacity available on the secondary market. As a result, the basis between Alberta and Ontario has increased to the minimum floor levels set by the TCPL interruptible transportation tariff.

In addition, in the summer of 2002 both TCPL and Alliance reduced available pipeline capacity for maintenance by amounts substantially greater than typical, and pipeline capacity into the Northwest was also limited by maintenance outages. During July, TCPL capacity east from Empress dropped to as low as 5.9 Bcfd, compared to announced winter capacity levels of 7.5 Bcfd. Capacity on Alliance dropped from maximum winter flow levels of 1.7 Bcfd to a low of 1.3 Bcfd. The decline in pipeline capacity flowing east from Alberta totaled as much as 2 Bcfd during parts of July, and has averaged about 1.5 Bcfd over the entire summer. As indicated in Figure 1-21, the decline in capacity has substantially constrained transportation on Alliance and TCPL for much of the summer, resulting in a substantial increase in pipeline basis, and a corresponding decline in Alberta wellhead prices.

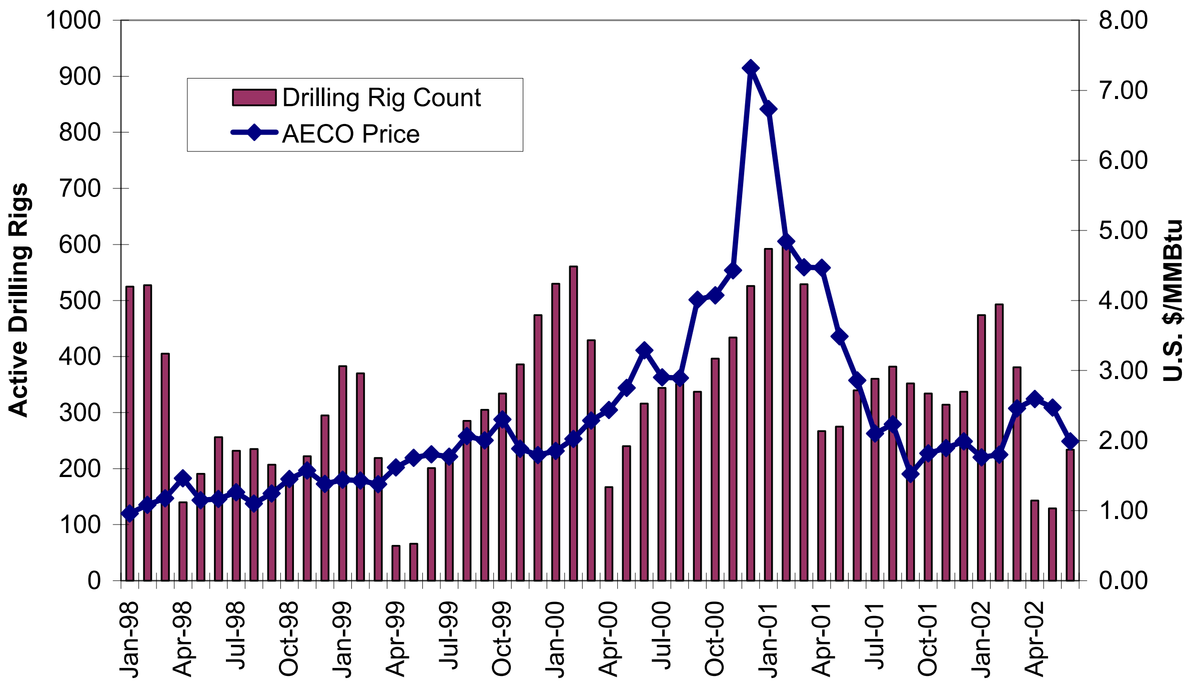
TCPL and Alliance are projecting a return to full pipeline capacity prior to the start of the winter heating season, hence EEA expects basis from Alberta to Chicago to fall to near the 80% TCPL interruptible floor prior to next winter. In the longer term, TCPL is trying aggressively to restructure tolls to increase the amount of firm capacity under contract. If TCPL is successful, EEA expects the Alberta to Chicago basis to again decline to close to variable costs, as excess firm capacity is again made available on the secondary market.

Impacts on Market Participants

Alberta natural gas markets are linked to eastern Canadian and U.S. markets by the TCPL and Alliance systems. When pipeline capacity on these systems is constrained, either due to growth in Alberta production or to pipeline outages, Alberta prices drop dramatically, and basis from Alberta to the eastern and southern markets increases rapidly.

The decline in Alberta prices has an immediate impact on exploration and development of new natural gas resources. Figure 1-22 illustrates this relationship. Drilling activity in Alberta peaked during the 2000 - 2001 period along with Alberta prices, but has fallen substantially in the last six months as Alberta prices have fallen in response to both the overall gas price decline and the increase in basis for transporting gas out of Alberta. This localized price collapse impacts drilling decisions and reduces supply development.

Figure 1-22
Canadian Active Drilling Rigs vs. Gas Price



On the other hand, the increase in basis provides an economic incentive to hold capacity on the pipelines leaving the region. In a competitive market, this provides an incentive to develop additional pipeline capacity. However, because all of the export capacity is owned by only three players (TransCanada Pipeline, Alliance Pipeline, and Westcoast Energy), and all of the pipeline capacity heading east is owned by only two players (TCPL and Alliance), the Alberta pipeline market would not meet most definitions of a competitive market.

1.4.4 Wholesale Electric Pricing Abnormalities in the Midwest During June 1998

Price Behavior – Midwest Wholesale Electric Market

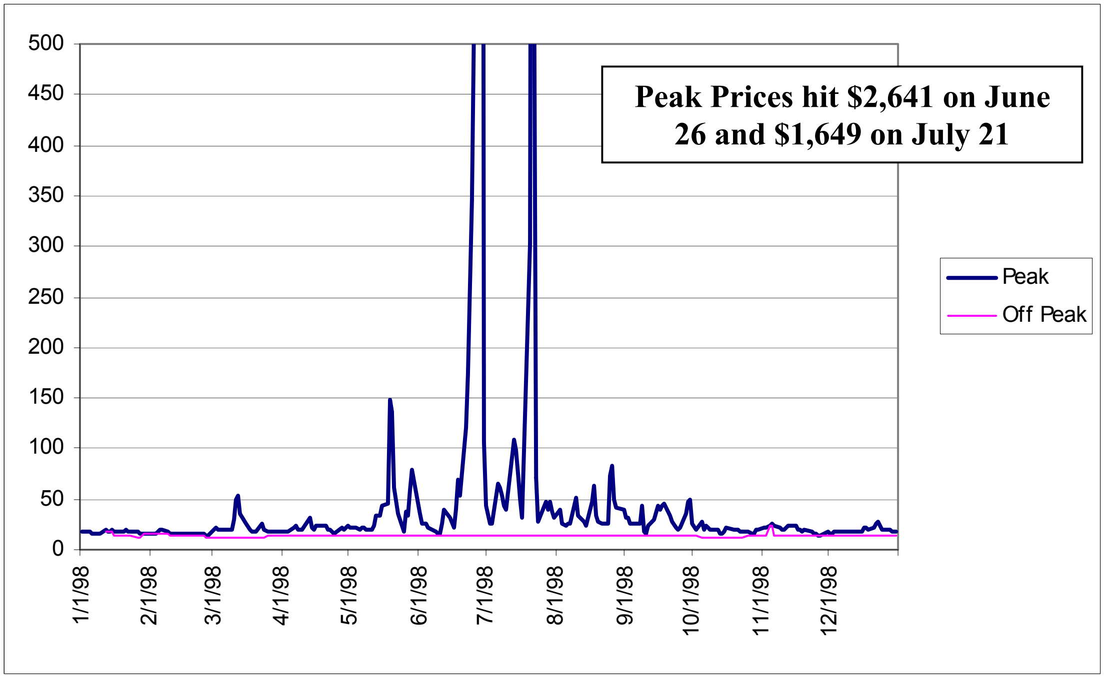
The week of June 22 – 26, 1998 saw dramatic price escalations in the short-term, wholesale electric markets in the Midwest. Next-day prices for electricity rose from $25 per MWh on June 25 to as much as $2,600 on June 26. The peak price on record was $7,500 for one hour, as paid by a midwestern utility for a 50MW transaction.[19] At the hourly and day-ahead markets, utilities were making significant levels of hourly purchases at $3,000 - $6,000 per MWh.[20] This price

[19] *Staff Report to the FERC on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998*, page 3-11.

[20] Ibid.

behavior, however, was short-lived and narrow in scope. Prices stabilized and by August 1998, the average price for sales into the Cinergy hub in the Midwest had settled down to $39.15 per MWh.

Figure 1-23
Peak and Off Peak Prices: Cinergy Hub



Source: Platt's

Factors That Caused The Price Spike

1) Systemic: Lack of Generating Capacity and Transmission Constraints

The price increases were observed in the short-term market and were rooted in systemic and long-term developments in generation, transmission and market demand, as detailed below.

Insufficient Generating Capacity

The long-term mismatch between demand and generating capacity contributed significantly to the price spike. In the ECAR and MAIN[21] regions, peak summer loads increased without being matched by an increase in generating capacity. From 1996 to 1998, the combined projected summer peak increased by 5.9%, from 127,788 MW to 135,321 MW for ECAR and MAIN, a rate higher than the 4.6% exhibited by the rest of the country.[22]

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21 ECAR is the East Central Area Reliability Council and MAIN is Mid-America Interconnected Network, Inc.
22 Ibid, page 2-1.

Table 1-2
Estimated Summer Resources and Demand

Estimated Summer Resources and Demand

	ECAR				MAIN		
	Available Resources	Net Internal Demand[1]	Available Capacity Margin		Available Resources	Net Internal Demand[1]	Available Capacity Margin
	MW	*MW*	*%*		*MW*	*MW*	*%*
June	102,617	83,568	18.60%		50,779	41,398	18.50%
July	102,510	90,330	11.90%		51,084	44,991	11.90%
August	102,396	89,272	12.80%		51,576	44,724	13.30%
September	101,669	79,684	21.60%		50,943	36,068	25.30%

[1] *Projected*

Source: North American Electrici Reliability Council, 1998 Summer Assessment

Available capacity margins in the region decreased from 17% in 1996 to 11.9% in 1998. In order to bridge this shortfall, Midwest utilities became more dependent upon purchases of power from other regions, like PJM and SERC, to meet peak demand.[23] However, there is a limit to the reliability of these outside sources of supply, as they can become unavailable if the source regions begin to experience high load conditions as well. For example, on June 25th, the areas throughout the Eastern Interconnection experienced high loads because of hot weather. PJM experienced generation alerts and cut back on transfers to ECAR.

High Levels of Outages

The decline in available generation capacity was partly due to planned and unplanned outages. The region saw high levels of plant outages due to maintenance and repair, particularly in the summer of 1998. Nuclear plants in the MAIN region were scheduled for long-term outages over the summer. The ECAR region experienced a flurry of forced outages at plants that were supposed to restart after scheduled maintenance but encountered problems after startup. The inclement weather also played a part, as storm-related damage forced the temporary shutdown of some plants.

Transmission Constraints

Transmission constraints aggravated the situation. Areas throughout the Eastern Interconnection experienced extremely high loads, causing overloads on the transmission system.[24] Implementation of TLR orders[25] then further limited the sources of power in the market and aggravated the shortage situation.

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23 Ibid, page 2-1.
24 Ibid, page 2-17.
25 TLR is a loading relief procedure used in managing the transmission system of the Eastern Interconnection. TLR orders are applied to prevent overloads of key transmission facilities and occur throughout the year when loads are high and the transmission system is heavily used.

2) Environmental: Warmer Than Expected Weather

Weather is the primary driver of short-term electricity load. Extreme heat, particularly if unanticipated, geographically extensive, and sustained over several days, can lead to emergency conditions in the electricity system.

During the summer of 1998, higher-than-forecasted temperatures continued over a broad region. Temperatures rose more dramatically and lasted longer than predicted. Demand for electric power increased to near-record levels in the Midwest and neighboring regions. On Thursday, June 25, 1998, the average temperatures in Chicago, Detroit and Milwaukee were 12 to 16 degrees above normal.[26] This gap caused several utilities to have unexpected difficulties covering their loads, forcing them into the day-ahead and hourly markets to meet the shortfall.

In the case of the Midwest, the increase in temperature was evident over a large region. This limited the possibility that excess capacity in one area would be available to serve sharply higher requirements in other parts of the region.

In addition, storms damaged transmission lines and forced a shut-down of generating facilities in the Midwest and neighboring regions, further limiting supply.

3) Market Conditions: Low Confidence

Utilities and marketers forced to go to hourly market to fulfill obligations

With high temperatures driving loads to record peaks and forced outages further curtailing supply, a generation shortage developed in the Midwest.[27] Two types of players were driven to the hourly market: utilities that needed electricity to supply their native load and marketers that were trying to secure power to avoid defaulting on contracts.

Low market confidence

Federal Energy Sales defaulted on June 23, injecting some uneasiness to the market as participants worried about the solvency of their counterparties. The company's default also resulted in a cascading effect, as counterparties were left holding unfilled positions. A survey conducted by the FERC showed that most market participants were not affected. However their concerns regarding possible future defaults contributed to uneasiness in the market. As peak loads and market uncertainty increased, participants wondered whether sellers could deliver their contracted quantities of electricity. Market participants scrambled to secure power to meet contractual commitments, leading to higher than usual demand for short-term supplies.

[26] Ibid, page 2-5.
[27] Ibid, page 4-1.

Inexperience of market participants

The market participants' relative inexperience hampered their ability to respond effectively to market forces. Some companies were driven to buy at high prices due to inexperience in the hourly markets. Others were holding contractual commitments that they were unable to back because of the price spike and the increase in demand.

Impacts and Conclusions

The unique combination of events that lead to the 1998 electricity crisis is unlikely to recur in the near term. New capacity has been built since 1998, creating an increased capacity margin. In 2002, ECAR has improved to 21.5% and MAIN to 23.1%, compared to 11.9% for both regions in 1998. However, like the California energy crisis, the Midwest electricity market in 1998 highlights the sensitivity of markets and physical infrastructure to an unexpected confluence of events. As participants develop expertise in markets, they will be able to define and craft effective ways to limit exposure to future price volatility. Thus, the effects of crises can be mitigated and contained. However, if the physical infrastructure does not keep pace with demand, the system will remain vulnerable to similar crises, even though the causes may be different.

Note on Consumer Prices

As shown in Figure 1-24, the impact on consumer prices varied from state to state depending on the regulatory approach adopted in each state to setting consumer rates. Illinois, Nebraska and Missouri exhibited price increases during the middle of the year.

1.4.5 Northeast Distillate Oil Market in the Winter Of 1999 – 2000

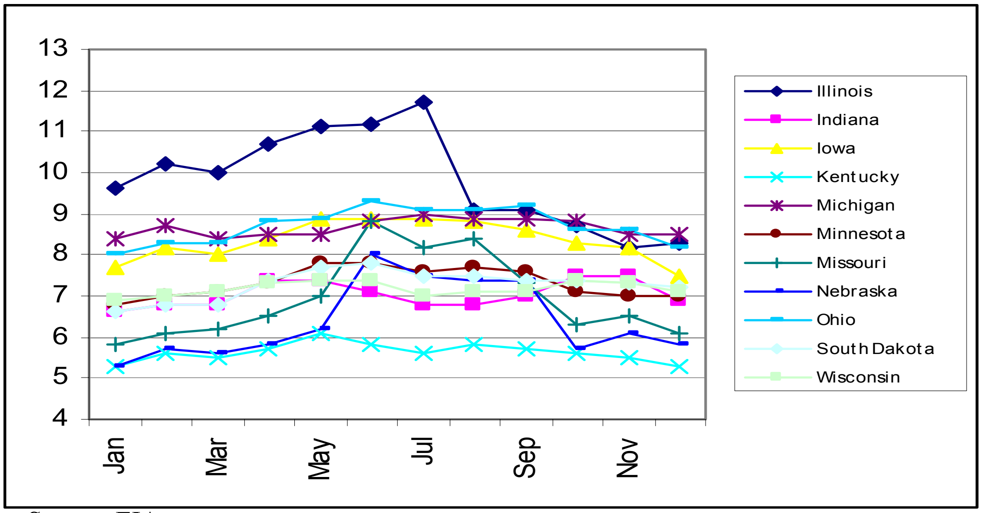
Distillate Oil Price Behavior: 1999-2000

During the winter of 1999 – 2000, spot prices for distillate fuel oil[28] increased dramatically in the Northeast. Between January 14 and February 4, 2000, New York Harbor spot prices for home heating oil increased by 133%, from $0.76 to $1.77 per gallon.[29] During a comparable time period, the residential prices for heating oil increased by 66%.[30]

Figure 1-25 illustrates the historical behavior of distillate oil prices. The New York price spikes began in the second week of January and lasted for one month. The imbalance between supply and demand eased as the warming weather reduced demand and higher imports increased supply, leading to lower prices by mid-February.

28 Defined as Number 2 high sulfur distillate fuel oil.
29 Energy Information Administration, *The Northeast Heating Fuel Market: Assessment and Options*, May 2000, p vii.
30 Ibid.

Figure 1-24
1998 Estimated Electric Utility Monthly Average Revenue for Residential Sector



Source: EIA

Figure 1-25
New York Harbor Spot Prices for Distillate Fuel Oil, August 1999 – March 2000

Factors Leading to a Price Increase

1) Low Heating Oil Inventory

Low inventory levels of heating oil set the stage for the price shock. At the beginning of January, distillate oil stocks were at an historical low. The low inventory levels decreased the ability of the market to respond to sudden demand or supply changes, thereby increasing the chances of a distillate price spike as the temperatures dropped.

Changes in the oil market were driving the inventory situation. Low prices in the world crude oil market had led to cuts in production. However, this was matched by a rapidly growing world demand, partly due to the revival of the Asian economies. Inventories of all crude oil and petroleum products were drawn down in order to supply the market.

Oil prices rebounded in 1999. However, the crude oil price increases were greater than the product price increase, resulting in smaller refining margins. The high crude oil prices and the decreased margins led to a reduction in the production of refined products, causing a nationwide drawdown of distillate fuel inventories toward the end of 1999. However, imports remained at an average level and thus, refined product inventories remained low. Table 1-3 shows the U.S. distillate fuel oil balance during this time period.

Table 1-3
U.S. Distillate Fuel Oil Balance, January – March 2000

Table 1: US Distillate Fuel Oil Balance

Week Ending	Product Supplied ('000 bpd)	Production ('000 bpd)	Imports ('000 bpd)	Exports ('000 bpd)	Stock Build (Draw) ('000 bpd)	Stock Level ('000 barrels)
1/7/00	3,007	3,341	252	157	429	122,700
1/14/00	3,766	3,138	231	160	(557)	118,800
1/21/00	4,364	3,198	152	157	(1,171)	110,600
1/28/00	3,866	3,267	160	147	(586)	106,500
2/4/00	4,192	3,259	105	158	(986)	996,000
2/11/00	3,866	3,471	528	147	(14)	99,500
2/18/00	3,716	3,392	452	157	(29)	99,300
2/25/00	3,761	3,445	718	159	243	101,000
3/3/00	3,386	3,577	200	148	243	102,700

Source: EIA, Department of Energy

2) Unexpected Demand

With inventory levels low, the market was not well equipped to deal with sudden changes in demand. Unfortunately, colder than average weather, year 2000 (Y2K) concerns and high prices for natural gas combined to create a surge in demand.

Cold Weather

Beginning in the third week of January 2000, temperatures in the New England and Middle Atlantic regions shifted from being 15% to 17% warmer than normal to being 24% and 22% colder than normal, respectively. This rapid change led to a 40% increase in the regions' weekly heating requirements.[31] The cold weather lasted until February 2000. Usage patterns changed as follows:

- Residential and commercial customers stepped up usage in order to heat homes and businesses.
- The colder weather also led to an increase in peak electricity demand. Power generators use distillate as a peaking fuel when natural gas is not an economically feasible alternative.
- Industrial customers with dual fired facilities also turned to distillate fuel, either to avoid the higher prices of natural gas or to comply with the terms of their interruptible contracts.

Table 1-4
Heating Degree Days, New England and Mid-Atlantic Regions, Winter 1999-2000

Heating Degree Days	Oct	Nov	Dec	Jan	Feb
New England					
30-Year Average	467	727	1078	1246	1060
Winter 1999-2000	487	629	981	1218	1017
Mid-Atlantic					
30-Year Average	399	667	998	1158	983
Winter 1999-2000	384	538	900	1126	917

Source: EIA

Y2KRelated Factors

Demand for distillate oil in December 1999 was higher than expected. EIA theorizes that some of the unexpected demand stemmed from Y2K concerns, although there is no firm data to support this speculation. [32] Utilities and other large-scale natural gas users minimized their exposure to natural gas pipelines by switching over to fuel oil during the Y2K rollover.

31 EIA, p 9.
32 EIA, page 7.

3) Storage and Delivery Problems

The low distillate oil inventories made it more difficult for suppliers to respond to the increase in demand. The supply-demand imbalance was exacerbated by structural factors such as storage and delivery problems.

The Northeast gets its distillate fuel oil from East Coast refineries and from more distant sources such as the Gulf Coast and imports from other countries. Since it takes weeks for incremental supplies to arrive from the more distant sources, response to surging demand is delayed. The situation in this case was aggravated by delivery problems. Tanker ships and barges were hampered by frozen waterways, delaying the arrival of new stocks to the New York and Boston harbors.

Resolution

The price spike was eased because of two events: a distillate oil supply adjustment and a decrease in demand. Imports of distillate fuel oil increased from a weekly average low of 152 thousand barrels per day in mid January, to a peak of 718 thousand barrels per day four weeks later in February. In addition, warming temperatures led to a decrease in demand, with U.S. demand dropping from peak weekly demand of 4.4 million barrels per day in mid-January to 3.7 million barrels per day by mid–February.[33]

Impact on High Natural Gas Markets

Natural gas and distillate serve as interchangeable fuels for boilers and generators. Large industrial consumers and power generators with dual-fuel capabilities will switch from gas to distillate oil and vice-versa depending on relative prices and the terms of utility tariffs and service contracts. This fuel-switching ability acts to insulate the gas and distillate oil markets from price spikes caused by substantial changes in demand. However, the ability to balance scarcity between the markets is only effective until the point at which the total supply of natural gas and distillate oil maintains margins for suppliers.

This balance was exhibited during the winter of 1999. Natural gas demand increased as temperatures dropped. The increased demand plus the low level of deliveries and the pipeline constraints into the Northeast resulted in a substantial increase in spot gas prices.

1.4.6 Summer 2002 New York City Natural Gas and Electricity Markets

New York City Energy Price Behavior

Prices for both natural gas and electricity spiked to levels substantially higher than normal in New York City in the summer of 2002. New York City spot market natural gas prices exceeded

[33] EIA Weekly Petroleum Status Report, DOE/EIA-0208 (Washington, DC, various issues), Table 10.

$10 per MMBtu (intraday), and spot market power prices exceeded $100 per MWH on several days. Figure 1-26 illustrates the price increase in natural gas over the summer.

Figure 1-26
New York City Natural Gas Price, January 1997 - July 2002

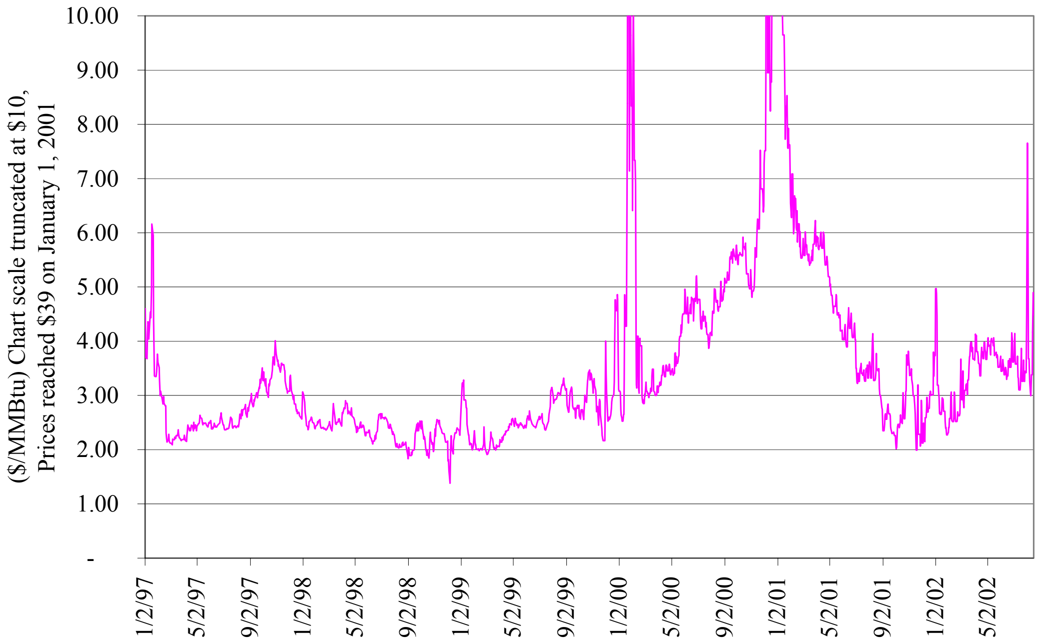
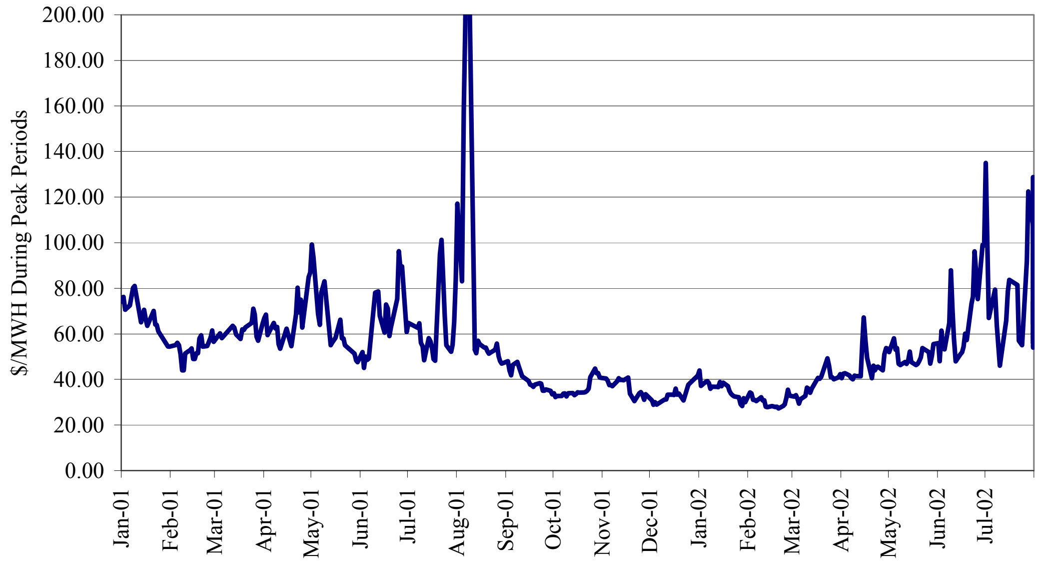


Figure 1-27 shows the marginal price of peak period power in New York City (region J of the NYISO) for the past two years. The high power prices during the 2001 summer months were due to constrained power generation capacity in the region combined with hotter than normal weather. July was 30 percent hotter than normal (456 cooling degree days vs. 353 CDD), while the first three weeks of August averaged 48 percent hotter than normal (360 CDD vs. 243 CDD).

Causes of the Price Increase

Both power generation capacity in New York City and interregional transmission capacity into the region have been increasing in the last several years. However, this growth has been insufficient to offset the growth in power demand. In addition, delays in certifying transmission capacity into the region and in completing new power generation capacity have slowed the availability of new power supplies. For example, general availability of the new 300 MW Cross Sound transmission cable has been delayed for a year due to lack of compliance with

Figure 1-27
New York City Peak Period Spot Electricity Price,
January 2001 - June 2002



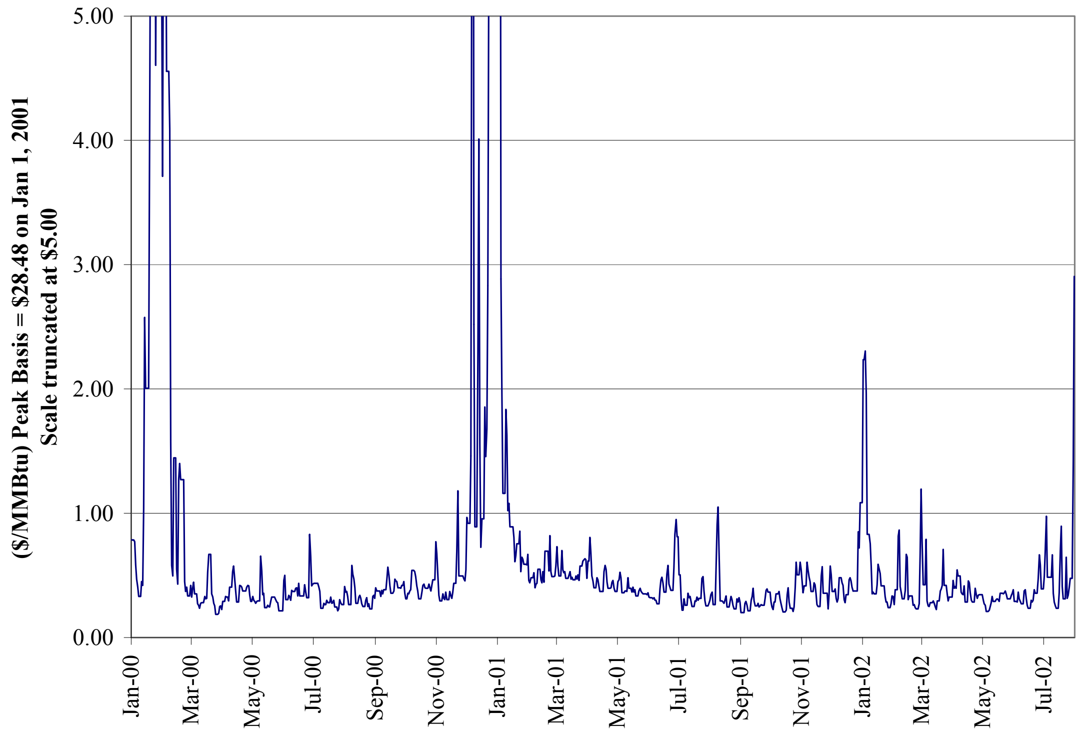
Source: Megawatt Daily
Prices reached $263 per MWH on Aug 9, 2001, and $241 on Aug 10, 2001

environmental permitting.[34] The Cross Sound Cable can supply about five percent of the region's power requirements on a peak day, hence will provide only short-term relief to the capacity constraints when fully on-line.

Natural gas turbine and combined-cycle facilities account for almost all of the growth in power generation capacity. In the last two years, 651 MW of new gas-fired capacity have been brought on-line. The increase in natural gas demand created by the growth in gas-fired power generation capacity led to the dramatic increase in natural gas prices in New York City during the summer of 2002, with prices exceeding $10 per MMBtu at Transco Zone 6 (NYC) at the end of July and into August. As shown in Figure 1-28, New York City gas prices regularly peak during the high demand winter months. However, the 2002 summer was the first time that prices peaked during summer months.

[34] In response to power constraints in New York City and Long Island during the summer of 2002, Secretary of Energy Spencer Abraham directed Cross Sound Cable Company to operate its 300 MW transmission cable from Connecticut to Long Island during New York power emergencies despite lack of certification by Connecticut (due to environmental permit compliance issues). Abraham's order states that "an emergency exists on Long Island due to shortages of energy, powerplants and transmission facilities." (*Platts Megawatt Daily*, August 19, 2002).

Figure 1-28
Basis from Henry Hub to New York, January 2000 - June 2002



We estimate that the hot July weather resulted in an increase in gas consumption relative to normal weather of 450 Mmcfd. New York City gas consumption averaged 1,750 Mmcfd, compared to our estimate of 1,300 Mmcfd that would have taken place in normal weather. Figure 1-29 illustrates our estimate of daily demand in the city during July, with daily demand sorted from highest to lowest. The figure illustrates a range of uncertainty re weather sensitive load. Peak day demand during July exceeded 2,000 Mmcfd, and may have reached 2,228 Mmcfd, a level perilously close to our estimate of summer pipeline capacity into the city of 2,306 Mmcfd. Winter pipeline capacity into New York City is estimated at 2,471 Mmcfd, but it declines by about 165 Mmcfd to 2,306 Mmcfd during the summer due to Transco pipeline operational constraints.

In addition, New York City has no gas production or underground storage. With the exception of several LNG peak-shaving and propane-air facilities that can provide up to 0.6 Bcfd of deliveries for a few days during the year, the region relies solely on pipelines for its gas supply. It is one of the most pipeline-constrained markets in the U.S. New York City does, however, have a significant amount of dual-fuel power generation capacity. Most of the existing steam facilities can be switched from natural gas to residual fuel oil, and some of the combined cycle facilities can be switched from natural gas to distillate fuel oil. As shown in Figure 1-30, a significant amount of power generation capacity has switched from natural gas to oil during previous high natural gas price periods. However, stringent environmental regulations restrict the total annual amount of fuel switching allowable, and seasonal environmental regulations restrict

Figure 1-29
New York City Daily Demand: July 2002
Normal vs. Actual Weather

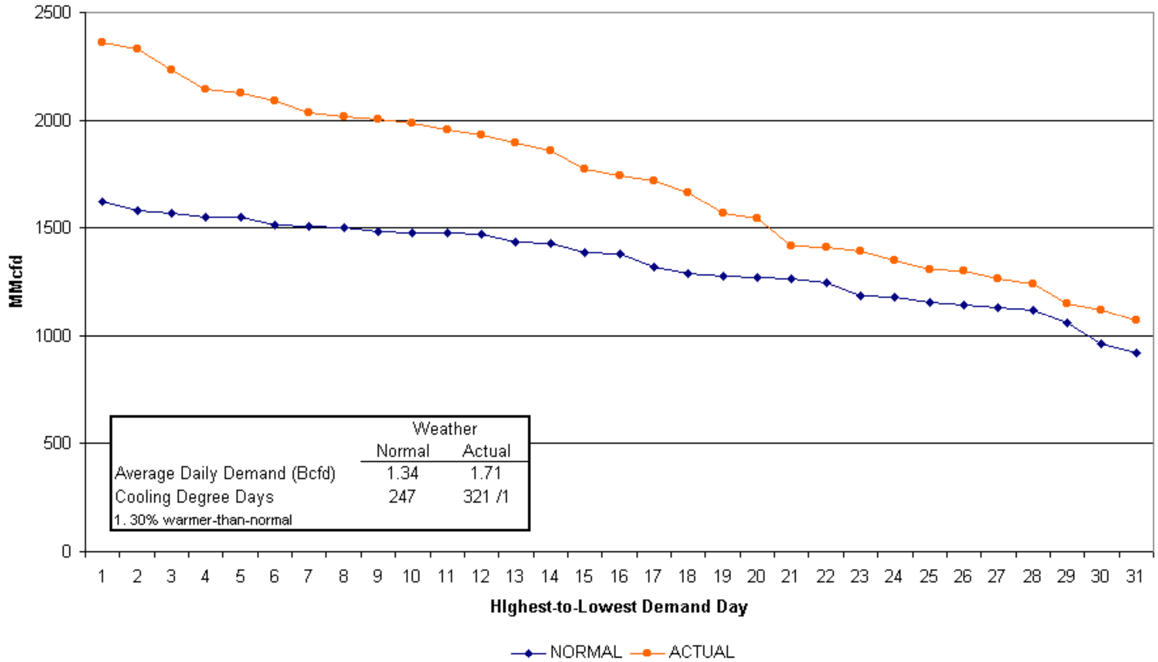
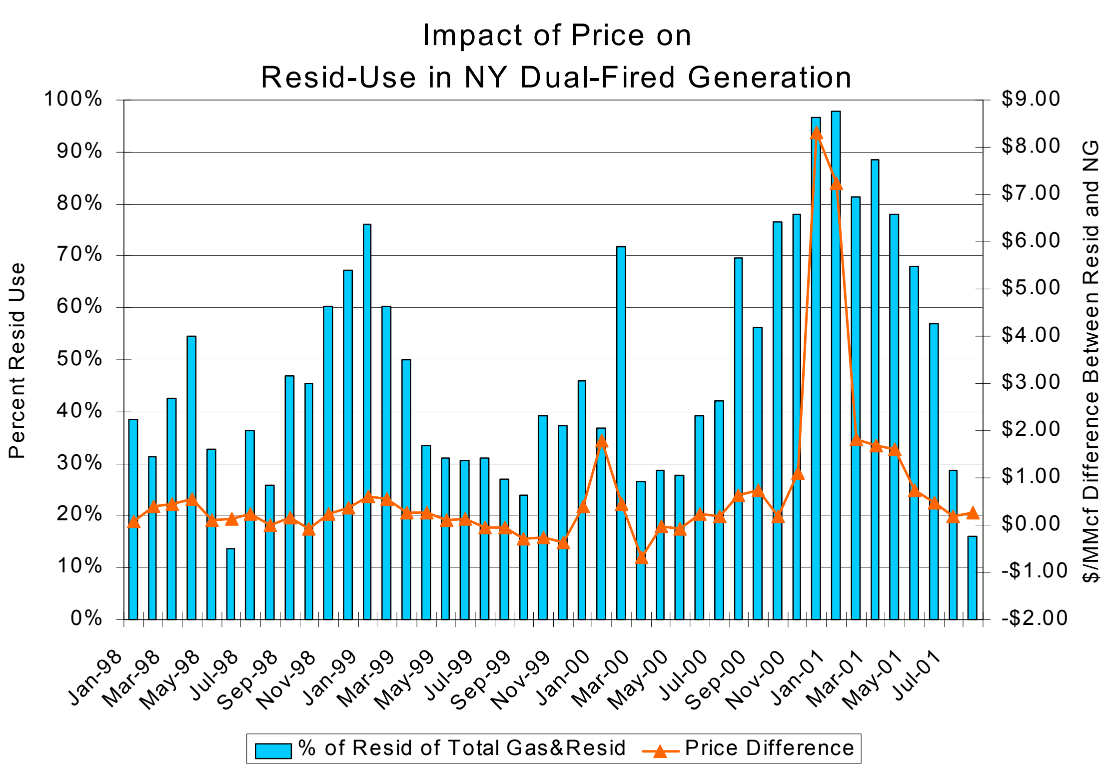


Figure 1-30



fuel oil consumption during the summer. In the past, fuel switching has been used extensively during the winter, but has not been a major factor during the summer months, when gas prices typically have been lower and gas demand has not approached the limits of pipeline capacity.

Historically, New York has been a major fuel-switching market, with a significant amount of dual-fuel steam generating units. Residual fuel oil determines the economics of fuel-switching for most of the existing capacity. New gas-fired turbine and combined cycle generation capacity will include some dual-firing capability. However, because the alternative fuel will be distillate fuel oil instead of residual, switching will occur at a higher gas price than switching in existing steam boiler units.

The direct cause of the spike in both natural gas and electricity prices was weather. High power demand due to much hotter than normal weather exceeded the capacity to produce power within the New York City load pocket, causing substantial price increases for power. The increase in power demand also increased the demand for natural gas, causing an increase in basis into New York City.

From a more fundamental perspective, the cause of the price spikes was structural. New York City and Long Island have insufficient power generation capacity to meet peak loads, and transmission capacity into the region is very limited. These electricity price spikes have occurred regularly in New York City for the past several years. However, 2002 was the first time that the increase in power generation demand also created a spike in natural gas prices. New York City has regularly experienced natural gas "basis blowouts" during the winter due to constraints on pipeline capacity into the region. However, 2002 was the first time this happened during the summer months. Demand for natural gas reached the limits of system capacity in 2002 due to growth in natural gas-fired power generation capacity and environmental and price constraints on fuel switching from natural gas to either residual fuel oil or distillate during the summer resulted.

As long as natural gas is used to meet incremental power generation load, we expect to see substantial swings in summer gas demand for power generation. Natural gas pipeline capacity into New York City is on the edge, and any activity that drives up demand can be expected to result in price spikes. For the foreseeable future, New York City will continue to be a pipeline-constrained market even with planned pipeline expansions, which could add up to 500 Mmcfd of new capacity over the next two years.

The traditional New York City winter price spike during normal, or colder than normal, winters is now matched by a corresponding summer peak during hotter than normal summers. Both winter and summer demand peaks are expected to increase over time, leading to higher gas prices, unless pipeline capacity expansions are allowed to keep pace with or exceed demand growth.

1.4.7 Key Conclusions from the Case Studies

While these case studies cover a variety of different fuels, locations, time periods, and circumstances, there are two elements that appear consistently in each of the case studies evaluated. All of the price events evaluated in the case studies resulted from resource or infrastructure constraints combined with a weather event that created additional demand on the limited infrastructure.

- In the North American natural gas market case study, a very tight supply situation was exacerbated by a much colder than normal early winter.
- The California case study illustrates the impact of limited power generation capacity and natural gas pipeline capacity, combined with a broad-based drought across the western U.S. that substantially limited power availability throughout the region.
- The Alberta case study highlights the impacts of constrained pipeline export capacity during the summer when local usage declines. In this case, warmer weather forced an overabundance of gas into the export market at the same time that pipeline capacity was declining due to outages and pipeline operational practices.
- The Northeast distillate fuel oil crisis in the winter of 1999 - 2000 was caused primarily by colder than normal weather, which increased demand while also constraining the ability to receive additional shipments of supply. This occurred during a time period with lower than normal starting inventories.
- The energy price spikes in the New York City market resulted from extreme weather (both colder than normal weather in the winter and warmer than normal weather in the summer), increasing demand beyond the capacity of the limited infrastructure to move natural gas and electricity into the area.

In each of these cases, the infrastructure existed to meet demand under normal weather conditions, but was and still is insufficient to meet unexpected surges in demand resulting from variations in weather patterns. Several of these price events were also preceded by unusual conditions that effectively reduced the ability of the market to respond to the unusual weather circumstances.

- The North American natural gas price spike was preceded by several warmer than normal winters that reduced prices and slowed development of new supply resources. The warm winters also resulted in losses in storage that discouraged investments in storage inventories during the injection season prior to the price spikes.
- The California energy crisis was also exacerbated by a lack of natural gas in storage. Storage had not been needed in the previous few years, and (with the exception of the regulated distribution companies) storage customers were unwilling to inject high-priced gas into storage, given the price behavior during the withdrawal periods in the previous couple of years.
- The Northeast fuel oil crisis was caused in part by low inventory levels created by marketers attempting to reduce inventory-related business costs.

1.5
IMPACT OF ENERGY PRICE VOLATILITY ON MARKET PARTICIPANTS

1.5.1 Introduction

Energy price volatility has a wide range of impacts on market participants. These impacts differ substantially for different elements of the market. Impacts range from increases in budgetary and planning uncertainty experienced by energy consumers, to delays or changes in energy providers' capital investment patterns, to potentially fatal liquidity crises for energy marketers and merchant power provides.

1.5.2 Impact on Consumers

Impacts on Residential and Small Commercial Customers

Most LDC firm service customers are insulated from day-to-day volatility in natural gas prices. Firm service customers, who account for almost all residential deliveries and about 63 percent of total commercial deliveries, purchase natural gas at regulated rates from the LDC. The cost of natural gas to these customers is set by regulation, and generally reflects the rolled-in average cost of natural gas to the LDC Citygate plus the LDC distribution charge. The rolled-in average cost of gas is subject to regulatory review, and there are typically delays ranging from one to three months before changes in the rolled-in average cost of gas are reflected in rates. In addition, most LDCs hedge gas prices to a certain extent, either through physical means (natural gas storage), contractual means (monthly and seasonal gas purchase contracts), or via financial hedges such as gas price collars purchased in the futures markets. As a result, the gas prices faced by these users do not vary with short-term (day-to-day or week-to-week) changes in energy market prices. However, persistent price changes, such as the winter-long increase in natural gas prices that occurred during the 2000 - 2001 winter, do result in substantial price increases.

In the short-term, residential and commercial customers tend to be fairly insensitive to energy prices. They tend not to see short-term variations in prices, and generally have little flexibility in adjusting consumption in response to prices. In general, these customers tend to be sensitive to total bills, not prices, and do not see the impact of commodity price movements until the bill arrives, at which time it is too late to change behavior.

For most of these customers, energy use is weather-dependent. Natural gas consumption is driven primarily by heating requirements, hence the conditions that generally result in high natural gas market prices (colder than normal weather, resulting in higher than normal heating load), also result in more consumption by these customers. During persistent high price periods, the combination of increased consumption and higher prices can have substantial impacts on total energy bills. Table 1-5 illustrates the impact on total natural gas bills for residential and firm service commercial customers in Pennsylvania of the combination of higher consumption and higher prices on the average winter heating season natural gas bill in the 2000/2001 winter. For residential customers, consumption increased by 15 percent, and average gas prices increased by 36 percent in the 2000/2001 winter relative to the 1999/2000 winter, resulting in an increase in the average residential gas bill in Pennsylvania of 55 percent from one winter to the next. For firm service commercial customers, the average gas bill in Pennsylvania increased by 50 percent over the same period.

Table 1-5

Natural Gas Winter Heating Season Bills in Pennsylvania

Residential Consumers

	Average Deliveries per Customer (Mcf)	Average Price ($/Mcf)	Average Heating Season Bill ($)	Percent Difference from 1999 Winter Heating Season
Winter 1999-2000	69.2	7.57	524	n.a.
Winter 2000-2001	79.3	10.26	814	55%
Winter 2001-2002	58.4	8.93	521	-0.3%

Commercial Consumers

	Average Deliveries per Customer (Mcf)	Average Price ($/Mcf)	Average Heating Season Bill ($)	Percent Difference from 1999 Winter Heating Season
Winter 1999-2000	424	7.01	2,968	n.a.
Winter 2000-2001	448	9.96	4,463	50%
Winter 2001-2002	365	8.32	3,039	2%

Source: Natural Gas Monthly and Natural Gas Annual, EIA

In the longer-term, residential and commercial customers make decisions about investments in new energy equipment based in part on past energy price behavior. Hence, a price spike such as that which occurred during the 2000/2001 winter is likely to have a persistent impact on future consumption, as high prices stimulate investment in higher efficiency furnaces and other energy-saving technologies.

Impact of Price Volatility on Industrial Customers

Industrial customers can be much less insulated from changes in energy prices than either residential or commercial customers. LDC sales account for only a small percentage of industrial natural gas demand (about 17 percent in 2001). The remainder is provided by the LDC via gas transportation services. Customers purchase the natural gas commodity either at market prices, or hedged through a natural gas marketer.[35] In both cases, industrial customers react to market prices. If the customer does not have any hedged supply, the customer will be purchasing at market prices. Even if gas supplies are hedged, the industrial customer typically would value the natural gas at opportunity cost value, which in any liquid market would be the market price.

In addition, industrial customers tend to have more options for reducing gas usage in response to price increases. Many industrial applications feature dual-fuel capability, and can be switched from natural gas to residual fuel oil or distillate fuel oil when natural gas prices exceed fuel oil prices (and vice versa). Under particularly high gas price scenarios, industrial facilities can also choose to shut down production rather than use high-cost natural gas. During the peak price periods in 2000 and 2001, very large amounts of industrial ammonia production capacity were shut down in response to high natural gas prices.

As a result, industrial customers tend to be more price sensitive than commercial or residential customers. The price sensitivity is reflected in both day-to-day operational decisions, and in long-term investment decisions in energy technologies.

Impact of Price Uncertainty and Volatility on Industrial Distributed Generation

Table 1-6 presents the technology cost and characterization data for a 5 MW CHP application.[36] In this example, the industrial customer operates the equipment as a baseload unit, satisfying their thermal requirements first, and purchasing any additional electricity required (beyond what is generated by the CHP unit) or selling any extra electricity generated to the grid. The buy-back electricity price is estimated by reducing the average purchased electricity price (as reported by EIA) by 20 percent.

An industrial customer with this type of distributed generation facility achieves cost savings from the electricity and thermal energy produced by the CHP unit. Table 5-3 also presents the results of an economic analysis of this unit under different natural gas and electricity price scenarios in the Pennsylvania area.

The impact of the alternative energy price scenarios on the payback period associated with this type of industrial energy technology illustrates the sensitivity of industrial energy consumption decisions to price volatility. In this case, the distributed generation technology exhibits high returns under the base case energy price forecasts. However, the high gas price scenario illustrates the sensitivity of the economics to the energy prices. In this case, the technology's economics deteriorated by 25% . For a risk-averse customer, the uncertainty regarding energy prices would be very likely to decrease the desirability of an investment in this technology.

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[35] The larger industrial consumers can consume enough natural gas to make direct price hedging attractive, hence providing some insulation from price changes.

[36] Based on new generation advanced reciprocating engine system (ARES) technology.

Table 1-6
Impact of Price Uncertainty on Industrial Distributed Generation
(5 MW ARES CHP Unit)
Technology Cost And Performance Data

	Capital ($/kW)	Non-Fuel O&M ($/kWh)	Power to Heat Ratio	Electrical Heat Rate (HHV Btu/kWh)
5 MW ARES Industrial Combined Heat and Power Generator	1,269	0.0107	0.91	7,817

Economic Assessment Results

	Initial Investment ($)	Net Present Value ($)	Simple Payback (# of yrs)
Base Case	6,341,860	12,237,600	4.5
High Natural Gas Prices/ Low Electricity Prices	6,341,860	9,237,537	5.0
Low Natural Gas Prices/ High Electricity Prices	6,341,860	15,237,664	4.0

The annual cash flow associated with this type of an investment is also subject to price volatility risk. Table 1-7 shows the year-to-year changes in operating cash flow for this investment using Pennsylvania natural gas and electricity prices for the 1999 - 2001 time period to estimate operating costs and savings.

Table 1-7
Annual Operating Cashflow for a 5 MW ARES CHP Facility
Based on Pennsylvania 1999 - 2002 Energy Prices

	5 MW CHP Operating Cash Flow
1999	Energy prices generate cash flow of $1.51 million
2000	Energy prices generate cash flow of $1.14 million
2001	Energy prices generate cash flow of $0.86 million
2002	Energy prices generate cash flow of $0.75 million

1.5.3 Impact on Energy Production and Delivery Companies

Impact on Gas LDCs

Energy price volatility presents a number of significant challenges to LDCs. Chief among these is the risk to the financial performance of the LDC created by the potential for significant shifts in gas price levels from one heating season or year to the next. When gas prices rise significantly compared to the previous year, the LDC faces additional risk in four distinct areas:

1) Financial risk related to decreased throughput,

2) Risk created by an increase in uncollectable accounts receivable (e.g., bad debt),

3) Increases in operating costs associated with increased shut-off and reconnect activity, and

4) Regulatory risk of disallowance of costs.

Volatility in gas prices – up or down – creates additional uncertainty in the planning process, making the capital budgeting process more difficult. The economics of a decision to expand the distribution system to hook up additional customers, or to spend resources in an attempt to develop a new market area such as distributed generation, gas cooling, or natural gas vehicles, is made much more uncertain. The additional complexity in planning for the development of the DG market is made doubly difficult because of volatility in electricity prices. The specifics of these impacts will be discussed in a separate report published as part of this series.

Financial Risk from Decreased System Throughput

Traditional utility ratemaking is designed to allow for the recovery of costs incurred by the utility plus a reasonable rate of return. However, the recovery of costs is not guaranteed. In most jurisdictions, the LDC is only assured a "reasonable opportunity" to recover its costs. As a result, an event that was not foreseen at the time of the last rate case or rate review can affect the financial performance of the utility. While in theory, the impact on financial performance can be positive or negative, in practice the risk is somewhat asymmetric, with greater risk of under-performance.

The structure of utility rates used in virtually all jurisdictions creates a financial performance risk associated with unanticipated fluctuations in system throughput. In order to understand the nature of this risk, it is necessary to understand certain basic aspects of traditional utility ratemaking. Appendix A presents an overview of the key ratemaking issues associated with these risks.

Impact of Unanticipated Changes in Throughput Due to Volatility

Because most utility rates are designed to recover a significant portion – often 30 percent or more - of fixed costs through volumetric charges, unanticipated changes in throughput due to price volatility can affect the recovery of the revenue requirement and the financial performance of the utility. The impact of energy price volatility depends upon the cause of the price movement and the response of the consumer.

If the price volatility is driven by cold weather that encompasses the LDC's service territory, the immediate impact of the consumer's conservation response is offset by the direct increase in throughput caused by the cold weather. In most instances, the weather impact overwhelms the price-induced conservation during the period of the cold weather. This effect occurs for two reasons. First, in the short-term, a residential or commercial heating customer has relatively few options to reduce consumption. Most of the reductions are accomplished through thermostat turn-back. While the use of additional insulation, weather stripping, furnace maintenance, or other improvements can reduce consumption, often they are not completed for weeks or months later. Second, the heating customer does not receive the "price signal" to consume less until the arrival of the monthly bill at the earliest. Even then the gas cost recovery mechanism usually dilutes the price signals. (See the discussion on consumer price impacts in section 5.3).

However, for months and years after the price spike event, per-customer consumption may decline. This results from any permanent improvements undertaken, such as appliance replacement and insulation addition, and from loss in market share in the new and replacement markets. Discussions with LDCs indicate that as much as half of the per-customer reduction in demand is permanent. While it is not possible to validate this conclusion statistically at this time, the result is consistent with the overall trend in declining use per customer that has been documented in various studies. For example, A.G.A. estimated that 76 percent of the decline in residential use per customer observed from 1980 through 1997 was attributable to changes in housing characteristics and appliance efficiency gains.[37] Both of these factors are more or less permanent once the actions are taken.

Risks of Increases in Uncollectable Accounts Receivable

When gas bills rise, utilities can experience a significant increase in uncollectable accounts receivable. Consumers often pay other bills before paying utility bills because of the protections against loss of service that are included in most utility tariffs. As a result, in periods of high gas prices, uncollectables can grow substantially above the level anticipated in the regulated rate.

There is no comprehensive, publicly available database that documents changes in uncollectables. However, in the wake of the increase in gas prices that occurred in the winter of 2000-2001, a number of utilities cited delinquencies as a negative contributor to performance in annual and 10-Q reports. Presenters at a number of gas utility conferences on the topic cited increases of 80 percent or more in uncollectables. In most instances, the utility will have little ability recoup these losses in future periods. The charges are reflected in reduced earnings.

[37] American Gas Association, *Patterns in Residential Natural Gas Consumption Since 1980*, EA-2000-01, February 11, 2000.

Risks of Disallowance of Gas Costs

Price volatility also increases the risks of regulatory disallowance of LDC natural gas purchase costs. Under the traditional cost of service model for gas utility rates, the cost of the gas and the cost of transportation storage services needed to bring the gas to the LDC Citygate are expenses that are recovered directly in the utility rates with no profit or earnings. Since these expenses represent a large percentage of the total cost to consumers, most state regulators include a forecast of these costs in rates. To the extent that the actual gas costs differ from those costs that are reflected in the rates, the positive or negative balances are accumulated in a “true-up” account and are surcharged or refunded through adjustments to the CGA in a subsequent period. The gas utility is responsible for prudently managing gas purchase costs, and recovery of gas purchase costs is generally subject to regulatory review.

Most LDCs hedge a portion of their natural gas purchase prices in order to reduce gas price volatility to customers, and to create a portfolio of natural gas supplies likely to be deemed prudent by their regulators. Hedging is accomplished using both physical means such as longer term natural gas supply contracts and natural gas storage, as well as, in some cases, financial hedging strategies including gas price options and collars. However, hedging is not a risk-free activity. While hedging can result in lower gas prices if the market prices are higher than expected, it can also result in costs higher than the market, if the market falls due to factors such as a warmer than normal winter. In cases where an LDC locks in prices that are higher than the actual market turns out to be, the LDC runs the risk that a portfolio will “out of the market”, with the potential for subsequent cost disallowances as part of a prudence review of gas purchase costs.

As natural gas volatility increases, and prices become more difficult to predict, the differences between the forecasted natural gas prices included in the LDC's nominal rates and the actual gas prices incurred by the LDC are expected to increase. The difference between incurred natural gas costs and the natural gas prices observed in the market is also expected to increase.[38]

Most differences between actual gas costs and the gas costs included in nominal rates are accounted for in routine regulatory proceedings. However, large differences between forecasted and actual gas costs, and between actual gas costs and market prices, can and often do attract high levels of regulatory scrutiny, with the associated risk of cost disallowances. This occurs both when natural gas costs increase above forecasts and LDCs face scrutiny for not locking in gas costs at the lower prices, and when prices fall below forecasts and LDCs can face scrutiny for locking in gas prices at too high a price.

The risks of these types of prudence reviews increase as the impacts of price volatility on consumers increases. Particularly in the aftermath of price shock periods, such as the winter of 2000 - 2001, there is often substantial political pressure to review the causes of the high energy costs to consumers, with subsequent risks of cost disallowances.

[38] Incurred gas costs will differ from actual market prices based on the gas purchasing strategies employed by the LDC. These include the use of storage, the mix of long-term and short-term purchases, and the amount of financial hedging used by the LDC.

Impact on Natural Gas Producers

Energy price volatility presents a number of significant challenges to natural gas producers. Natural gas price volatility creates uncertainty about the amount of revenue that can be realized from an exploration or development project. The impact of gas price volatility on gas producers is compounded by volatility in crude oil and liquids prices.

The volatility risk to gas producers does not arise from daily fluctuations that generate the opportunities for trading profits. Instead, the primary risk to producers is the longer-term cycling of gas prices that is generated by seasonal weather patterns, "boom-bust" investment cycles, variations in economic activity, and pipeline capacity constraints that can limit the ability of gas to move out of a production region.

Natural gas producers face many risks in doing business. Table 1-8 illustrates these risks, listing the various assumptions a producer must make in evaluating a drilling program. The table presents a 10-well program with parameters typical for the Lower-48 onshore. The major uncertainties include:

- Geologic risks of dry holes,
- Geologic and engineering risks in recovery per successful gas well,
- Economic and engineering risks regarding the cost of the wells, and
- Economic risks of the value of gas produced.

Table 1-8

Risk Assessment of a Typical Gas Well Drilling Program

Input Assumptions	
Number of Wells	10
Success Rate	80%
Expected Gas Price	$3.00
Gas Price S.D.	$0.50
Mean EUR/Well (MMcf)	900
Average Decline Rate	25%
Avr Cost per Gas Well	$900,000
Avr Cost per Dry Hole	$810,000
Annual O&M per Gas Well	$25,000
Results (Expected Values)	
Successful Gas Wells	8.0
Dry Holes	2.0
EUR/Well (MMcf)	900
Total EUR (MMcf)	7,202
D&C Cost Index	1.00
Total Capital Cost	8,820,000
F&D Cost $/Mcfe	$1.22
Net Present Value	$1,317,778

The middle and bottom part of Table 1-8 show “expected values” of the key parameters and how those values would play out over a 15-year investment horizon. Out of the 10 wells drilled, an average of 8 would be expected to be successful gas wells and two would be dry holes. Each successful well would be expected to produce an average of 900 MMcf of natural gas. The total investment cost of the program would be $8.8 million and the finding and development cost would be expected to be $1.22 per Mcf. The expected net present value of the program would be $1.3 million assuming a gas price of $3.00 per Mcf.

Because of various risks inherent in gas exploration and development, producers often evaluate investments using not only the “expected values,” but also probability distributions for each key parameter. For example, in the case presented in Table 1.8, the recovery per well could be described as having a lognormal distribution with a mean of 900 MMcf and a standard deviation of 700 MMcf. Similarly, the cost of the wells might be assumed to have a triangular distribution with a range 20 percent above and below the expected average. By making assumptions about the distribution of key parameters, it is possible to compute a distribution of the major financial decision criteria, such as net present value, that will be used to evaluate the investment. Figure 1-31 shows the cumulative probability distribution of the 10-well program under two different gas price volatility scenarios. The thin dashed line represents a gas price distribution with a mean of $3.00 and a standard deviation of $0.50. The thick solid line represents a higher volatility scenario, and is based on a gas price expectation with the same mean but a higher standard deviation of $1.00.

In both cases, the expected value of the 10-well program is $1.3 million. However, in the case with less gas price volatility, the chance of the program having an NPV of zero or less is 39 percent, while the chance of the program having an NPV of zero or less increases to 46 percent when the assumed gas price volatility increases.

The relative impact that gas price volatility has on investment risk tends to go up as the size of the drilling programs in any given area increases. The reason for this is that the geologic and engineering risks “average out” over a larger number of wells, leaving more of the resulting NPV variation due to product prices.

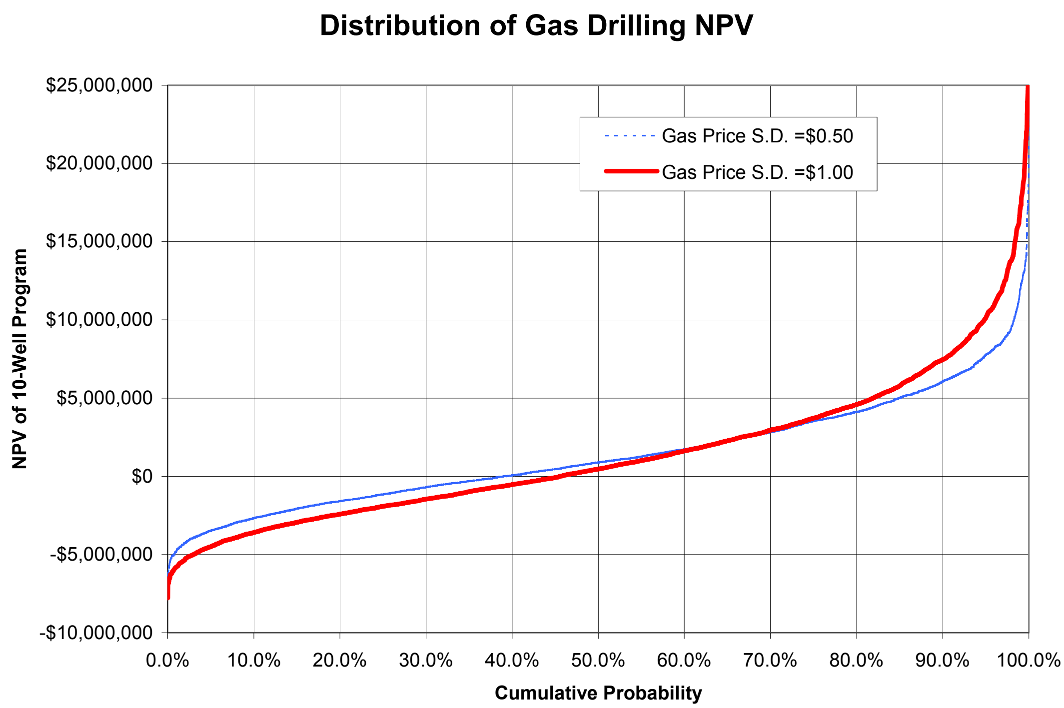
Increasing well decline rates can also exacerbate gas price risks for producers. A well that quickly produces a large percentage of its estimated ultimate recovery (EUR) is at greater risk from uncertainty in gas prices than a well with a flatter production profile. The rapidly producing well has a greater risk that most of the production will coincide with a period of depressed prices than a well that produces gas over a longer period of time. As decline rates have increased to speed cash flow, gas price uncertainty has created additional risk in production economics.

As a result of higher price risks, the effective “hurdle rate” for gas exploration and production is increased.[39] Producers delay new E&P projects until gas price expectations rise to a high enough level to make the probability of reaching the target financial criteria acceptable. In some ways, this adjustment is self-fulfilling. Delays in initiating drilling have the effect of maintaining a

[39] The “hurdle rate” is the minimum acceptable expected return needed for a project to proceed.

tighter supply-demand balance than would have existed if the projects had proceeded. As a result, the future prices are increased because of investment delays caused by the volatility.

Figure 1-31



The fluctuation in gas and oil production revenue also has the effect of increasing the cost of capital for producers. The impact is particularly significant to independent producers that do not have the diversified sources of internally generated funds available to larger producers. For an independent producer, the "riskiness" of the business can add two percentage points or more to the weighted cost of capital.

Capital markets can also limit available investment capital during higher price periods by requiring borrowers to use a lower than expected energy price forecast when evaluating project economics, in order to minimize risks to lenders. During the last half of 2002, we understand that most lenders were requiring producers to evaluate project economics using a long-term gas price of less than $3.00 per MMBtu, well below the existing prices at the time, and well below long-term industry expectations. Since many of the available projects were considered uneconomic at these prices, producer response to the higher natural gas prices was constrained. The increase in producer activity in the first half of 2003 corresponded with a loosening of lender project evaluation guidelines allowing producers to use long-term gas prices of around $4.00 - $4.50 per MMBtu to justify additional investments.

Finally, the "boom-bust" cycle in gas and oil exploration creates significant difficulties in attracting and retaining a skilled work force. Over the past 15 years, the U.S. gas and exploration industry has experienced 5 periods during which the work force was substantially reduced. Each of these periods of contraction resulted in the loss of skilled workers. But just as importantly, these contractions sent a less than desirable signal to young people entering the work force regarding the opportunities offered in a career in the exploration and production sector. As a result, the number of new petroleum engineers declined substantially.

Impact on Electricity Generators

The power generation market remains a very localized market. Transmission constraints and regulatory boundaries result in a number of different markets responding differently to price volatility.

In regulated markets, the price of natural gas represents one element of the cost of service for the electric utility. As gas prices fluctuate, costs are generally passed through to electricity ratepayers. In these markets, the short-term financial impacts of increased gas price volatility are determined by the regulatory structure. In regions where costs are passed directly through to consumers, the financial impact on electric utilities is tied to changes in throughput resulting from fluctuating power costs. In all regions, substantial increases in costs are likely to result in additional regulatory scrutiny, and thus impose additional regulatory risks on the utility.

In areas where the wholesale power markets have been deregulated, producers are subject to the vagaries of both the natural gas and electricity markets. Energy price volatility increases the uncertainty associated with both power generation costs (e.g., fuel costs) and with the price of power sold into the market. However, in many markets, the increases in energy price volatility tend to be linked, and tend to offset each other. In much of the country, natural gas-fired generating capacity provides the majority of the marginal power generation capacity, primarily meeting shoulder and peak period loads. In a market with competitive wholesale electricity markets, such as the Pennsylvania-New Jersey-Maryland power pool (PJM), increases in natural gas prices tend to result in increases in wholesale power prices. In a market where the gas-fired generation is needed, the electricity price will be high enough to justify almost anything for gas supply, ***provided the electricity price in the market is not capped.*** As a result, revenues increase when costs increase, and decrease when costs decrease.

For merchant power generators operating in regions where natural gas-fired generation is not setting the marginal price of power, fluctuations in natural gas prices can have a significant impact on operating cash flow. Natural gas price volatility results in increases or decreases in natural gas price that will not be fully offset by changes in power prices, resulting in increases in cashflow volatility. The increase in cashflow volatility results in an actual or perceived increase in risk, with impacts on stock prices and bond ratings. This effectively increases the cost of capital and decreases capital available for new investments.

In addition, volatility in gas prices – up or down – creates additional uncertainty in the planning process for both regulated utilities and merchant power companies. The additional uncertainty decreases the attractiveness of natural gas-fired generating capacity (other things being equal). Changes in natural gas prices fundamentally influence the economics of new power generation capacity. Almost 100 percent of new fossil fuel power generation is natural gas-fired capacity. Natural gas power plants typically have a lower up-front capital cost and a higher operating cost relative to alternative technologies such as modern coal powerplants. Hence, the economics of a natural gas-fired power plant is dependent on future natural gas prices. As natural gas price volatility increases, the risks of major investments in gas-fired capacity increase, and natural gas capacity becomes less attractive relative to coal and other alternatives with more stable fuel costs.

Electricity price volatility has much the same impact as natural gas price volatility from the power producer's point of view. The direct impact of electricity price volatility on operational cash flows increases credit risk, hence increases the borrowing costs associated the long-term debt needed to finance most power plant projects. The increase in cashflow risk associated with an increase in volatility also increases the rate of return required to justify additional capital investments. Both impacts increase the effective cost, and decrease the potential returns associated with investments in new powerplants.

Impact on Natural Gas Pipeline Companies

Natural gas price volatility influences short-term pipeline operations as well as long term pipeline expansion decisions. In the short-term, volatility in throughput affects the pipeline basis, and the amount that shippers are willing to pay for pipeline transportation services. When price volatility is the result of pipeline constraints, holders of pipeline capacity can profit during periods when the pipeline is constrained. During these periods, the pipeline basis will exceed the contracted cost of holding capacity, and contract holders can profit by releasing capacity or packaging natural gas for resale on the "grey" market. While the pipeline companies themselves are generally prohibited from selling capacity at greater than maximum rates, unregulated marketers often hold capacity on the pipelines, and can profit during periods of constrained capacity.

However, the short-term fluctuations can obscure the longer-term pipeline trends. In the longer-term, price volatility decreases the willingness and the ability of the pipelines' major customers to sign the long-term contracts for new capacity necessary to initiate development of new pipeline projects. For the past several years, most of the new pipeline capacity has been supported by long-term contracts to provide natural gas to new power generation facilities. However, price volatility and the associated liquidity crises in the merchant power industry have significantly decreased the ability and willingness of power generators to sign the long-term capacity contracts needed to support major pipeline expansion projects.

As a result, for the foreseeable future most pipeline expansion projects are likely to be initiated only when LDCs or producers are willing to sign long-term contracts for the additional capacity. However, the increase in price volatility has a rather dramatic impact on the willingness of producers to make such long-term commitments, and also increases the risks to LDCs of making long-term commitments.

In addition, the large integrated energy companies that own most of the major pipelines are currently suffering from their own liquidity problems. As bond ratings and stock prices have fallen, the cost of investment for capacity has increased, making all investments more difficult and expensive.

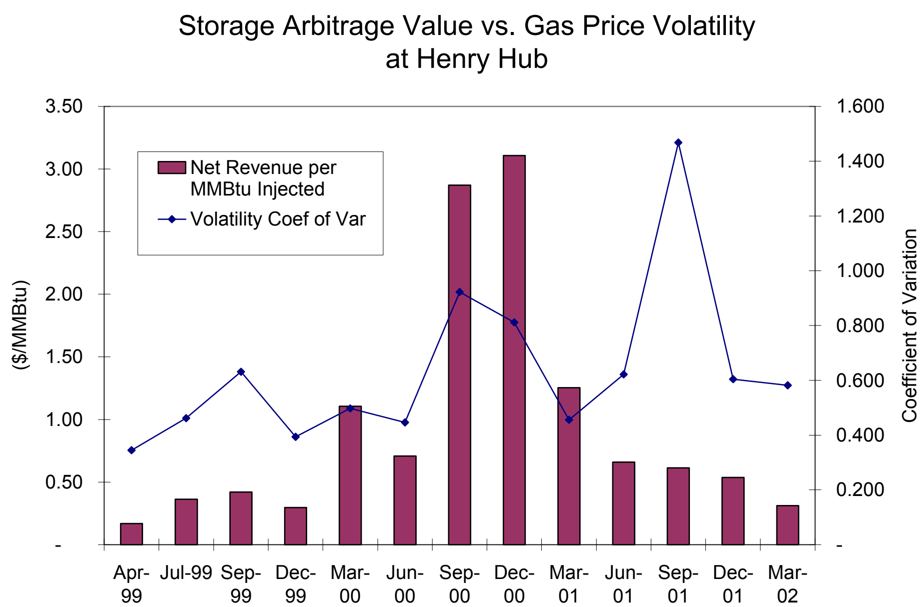
Natural Gas Price Hedging and Arbitrage

An increase in energy price volatility increases the importance of natural gas price hedging for many of the participants in the market. The increased volatility also increases the opportunity for price arbitrage. As a result, companies that can provide hedging services can benefit from the increase in volatility.

The largest of the financial arbitrage markets is the NYMEX Henry Hub contract. As price volatility has increased, so has the volume of Henry Hub transactions, along with an increase in the price of the hedging instruments. However, as discussed in Section 2-5 of this report, the increase in volatility also increases the costs of hedging.

Price volatility has a significant impact on the value of physical arbitrage, primarily natural gas storage. Traditionally, natural gas storage has been used for seasonal supply reliability and for seasonal price arbitrage. However, recent trends in natural gas markets have also increased the value of short-term physical arbitrage opportunities. As natural gas price volatility increases, so does the value of arbitrage using physical storage. Figure 1-32 illustrates the potential monthly value of injecting natural gas into storage during low price days, and selling gas into the market during high price days, relative to the overall amount of price volatility over the course of the quarter. The values in this figure are estimated based on the cycling capabilities of a salt cavern storage facility, and reflect perfect foresight concerning future natural gas prices. Note that the value of storage arbitrage is linked to the overall direction of gas prices as well as to the level of gas price volatility. During the later half of 2001, when prices were falling, the value of storage arbitrage declined even though volatility was increasing.

Figure 1-32



1.6
CONCLUSIONS

Energy prices have become increasingly volatile over the past decade.

The large capital requirements and significant lead times associated with energy production and delivery make energy markets more susceptible to the imbalances in supply capability and demand that result in price volatility. The natural gas and electricity industries have exhibited a particularly large increase in price volatility. These industries have responded to market and regulatory pressures to improve efficiency and reduce costs by reducing the amount of underutilized supply capability that is needed to moderate volatility.

Commodity markets exhibit increased volatility when there is little or no underutilized supply capability to meet natural fluctuations in demand. In order to remain competitive and profitable, or to comply with regulatory requirements, companies have an incentive to increase efficiency and reduce the amount of unutilized capacity or assets held by the company.

The large capital requirements and significant lead times associated with energy production and delivery make energy markets more susceptible to the imbalances in supply capability and demand that result in price volatility.

Energy markets such as natural gas, electricity, and heating oil are particularly susceptible to market and price volatility because fluctuations in weather can change the underlying demand for the commodities significantly, and the increase or decrease in demand affects all of these commodities in the same direction.

Barring structural changes, natural gas markets will be at least as volatile or more volatile in the future.

The large increase in gas-fired power generation capacity characterized by rapid and less predictable swings in gas requirements will increase fluctuations in natural gas demand. The majority of the new natural gas power generating stations will not be operated as a baseload source of power. As a result, they will cycle on and off as the marginal sources of electricity supply, leading to larger day-to-day swings in natural gas demand. In addition, the limited amount of dual-fuel capacity being installed in new power plants compounds the effect of the plants on gas market volatility. In fact, large amounts of dual-fuel power generation would have the impact of moderating gas market volatility.

Environmental restrictions that limit the ability of large gas loads to switch to oil during periods of tightness in the gas market also can increase gas market volatility. Public opinion and policy have yet to recognize the linkage between price levels and price volatility with environmental restrictions.

In the short-term, capital constraints that have developed in the wake of the Enron bankruptcy and decline in equity prices for many energy marketers will continue to inhibit the flow of investment into natural gas and electricity infrastructure to at least some degree. It is not clear how long these capital constraints will last, but the impact will be felt for at least several years after the constraints are alleviated.

Finally, public policy and natural gas industry regulation continues to focus on short-run economic efficiency that inhibits the use of long-term contracts and the investment in facilities that provide a reserve supply capacity. While there has been increased discussion regarding the desirability of longer-term contracts and the need for additional infrastructure, there remains no consensus regarding the appropriate mechanism to provide economic incentives for such investment or to allow for the recovery of costs that may be "at risk" in the commodity market.

However, energy price volatility creates uncertainty and concern in the minds of consumers and producers, who may delay decisions to purchase appliances and equipment or make investments in new supply. Such delay may result in lost market opportunities and inefficient long-run resource allocations. In addition, volatility may create pressures for regulatory intervention that can bias the market and penalize regulated entities and market participants by generating wide and unpredictable revenue swings. Finally, volatility can hurt the image of energy providers with the customers and policymakers and create doubt about the industry's integrity and competency to reliably provide a vital economic product.