NATURAL GAS AND ENERGY PRICE VOLATILITY

PREPARED FOR THE
OAK RIDGE NATIONAL LABORATORY

BY THE

American Gas Foundation

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October 2003

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3 Outlook for Future Natural Gas Price Volatility

3.1 INTRODUCTION

One of the primary objectives of this study 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. Prices move 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.

In this chapter of the report, we discuss the elements of energy markets likely to impact future price volatility, and forecast expected energy price volatility between today and 2020 based on the assumption that the basic structure of the energy market remains unchanged from today's structure. We then identify several possible alternative energy market scenarios that might result in different trends in price volatility. Finally, we evaluate the impacts of these volatility scenarios on the market penetration of new natural gas technologies, such as distributed generation (DG) and combined heat and power (CHP), and estimate the impact on price volatility that is likely to result from significant market penetration of DG/CHP.

This chapter of the report is structured into five sections. Section two reviews the factors influencing natural gas price volatility, including the impact of weather, economic factors (e.g., supply and demand trends, prices of competing products), current market conditions and regulatory structure on price volatility. Section three articulates the relationship between natural gas prices and price volatility, and examines historical data and shows that daily price volatility is a function of daily demand volatility and supply constraints. Section four evaluates long-term natural gas market trends. This section looks at the projected conditions of natural gas demand and supply. These trends are then evaluated and analyzed for their impact on price volatility. Section five expands on the previous section by presenting four alternative market scenarios and analyzing the potential impact on price volatility.

3.2 Factors Driving Future Natural Gas Price Volatility

Price volatility is driven by imbalances between natural gas demand and supply. 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 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, weather conditions are the primary driver of demand for natural gas and electricity. Because weather conditions can change rapidly and unexpectedly, large and sudden shifts in service demand can occur, creating imbalances that must be relieved.
- In the longer-term, prices signal the need to develop new resources or the opportunity to increase use of natural gas-based technologies, and provide the necessary incentive for a free market to invest in new resources and technologies.

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. After production or pipeline capacity is fully utilized, available supply changes very little regardless of price. As a result, once capacity is reached, the market equilibrates primarily based on demand price response.

3.2.1 Review of Factors Influencing Natural Gas Price Volatility

In this section of the report, we review the drivers of energy price volatility and differentiate the drivers in terms of the degree to which market structure, regulation, and participant behavior can influence them. The objective is to identify the drivers of volatility that can be influenced by changes in market structure or policy (e.g., infrastructure constraints), those that can be influenced only marginally (e.g., world crude oil prices), and those that cannot be influenced at all (e.g., weather patterns).

Demand Factors Influencing Volatility

1) Weather

In the short-term, the most influential factor in natural gas prices and price volatility is the weather. A colder than normal winter results in much higher natural gas demand, higher gas prices, and additional price volatility. The impact continues throughout the following summer and into the start of the following winter due to the delayed effects of higher storage withdrawals on the following injection season. A single colder than normal winter can result in lower prices after the following winter, when increases in supply stimulated by higher prices become available. A warmer than normal winter has the opposite impact on prices and price volatility.

Weather also influences electricity prices, with summer prices increasing or decreasing in response to warmer or cooler weather. However, weather does not have the long-term impact on electricity prices that we see on natural gas prices, due to a lack of systematic electricity storage.

EEA uses the Gas Market Data and Forecasting System (GMDFS) to capture the market dynamics necessary to simulate the market response to different weather patterns on a monthly basis. The EEA GMDFS provides an integrated framework to evaluate long-term natural gas market trends and to forecast natural gas and electricity market conditions through 2020. It assesses the impact of overall natural gas availability in the North American market, as well as regional supply constraints, such as pipeline capacity and storage inventory levels, electricity demand, power generation and power generation capacity.

Figures 3-1 and 3-2 illustrate GMDFS results representing the response of prices at Henry Hub to different weather patterns. These charts reflect 67 different forecasts of monthly gas prices using 67 different historical weather patterns, resulting in the summer and winter price distribution charts shown in these two figures. The base case observation identified in the charts reflects normal weather. In Figure 3-1, the observations with prices greater than the identified base case price reflect colder than normal winter weather, while the observations with prices less than the base case price occur when weather is warmer than normal.

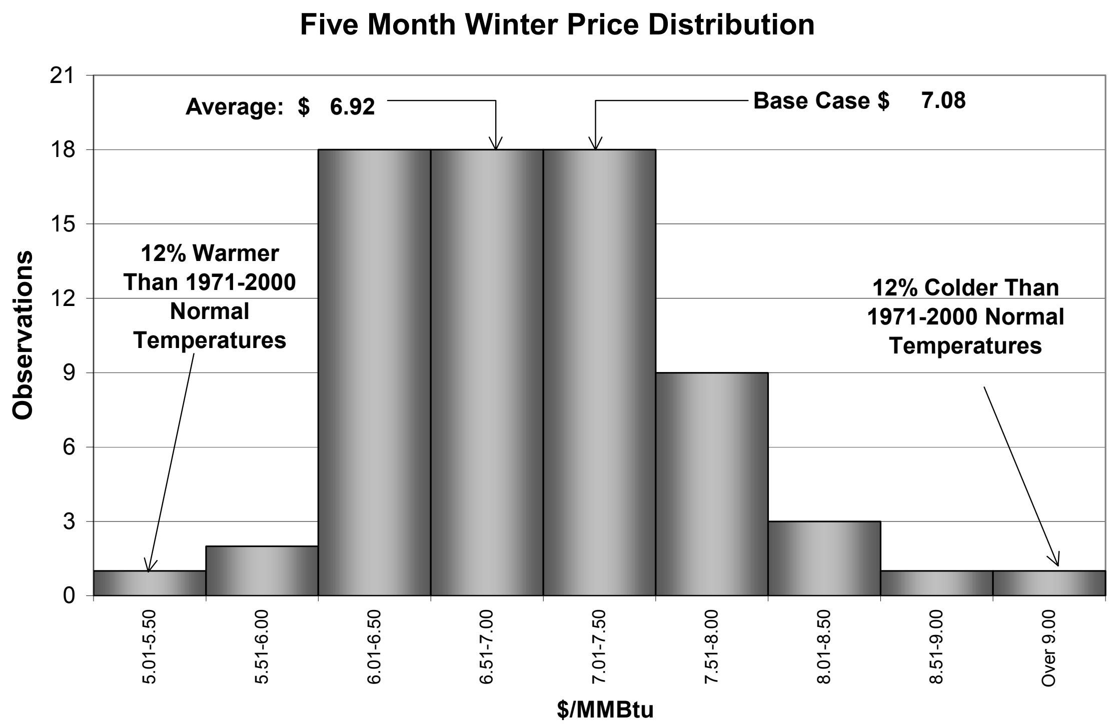
Day-to-day, month-to-month, and year-to-year weather patterns tend to be normally distributed around very long-term trends. However, price response to changes in demand due to changes in weather is not normally distributed. As illustrated in these charts, the impact of weather on prices tends to be asymmetrical, with colder than normal weather having a larger impact on natural gas prices than warmer than normal weather. This lack of symmetrical price response to differences in weather patterns is a fundamental feature of the market. As demand increases, and system supply constraints are approached, prices must increase by a larger amount in order to elicit additional sources of supply.

Differences in prices due to variations in summer weather tend to be more normally distributed than differences in winter prices.

Colder than normal weather also tends to have a greater than normal impact when prices are relatively high due to interactions with fuel switching (which is discussed in detail later in this report). Natural gas demand elasticity declines when prices increase and as demand switches away from natural gas to residual fuel oil or distillate fuel oil. When natural gas prices are competitive with oil prices, the price elasticity of demand tends to be relatively high. At this point, energy demand switches between natural gas and fuel oil, stabilizing 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. In very tight markets when most of the switchable capacity has shifted 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.

Figure 3-1

Projected Impact of Weather On 2003/2004 Winter Gas Prices At Henry Hub



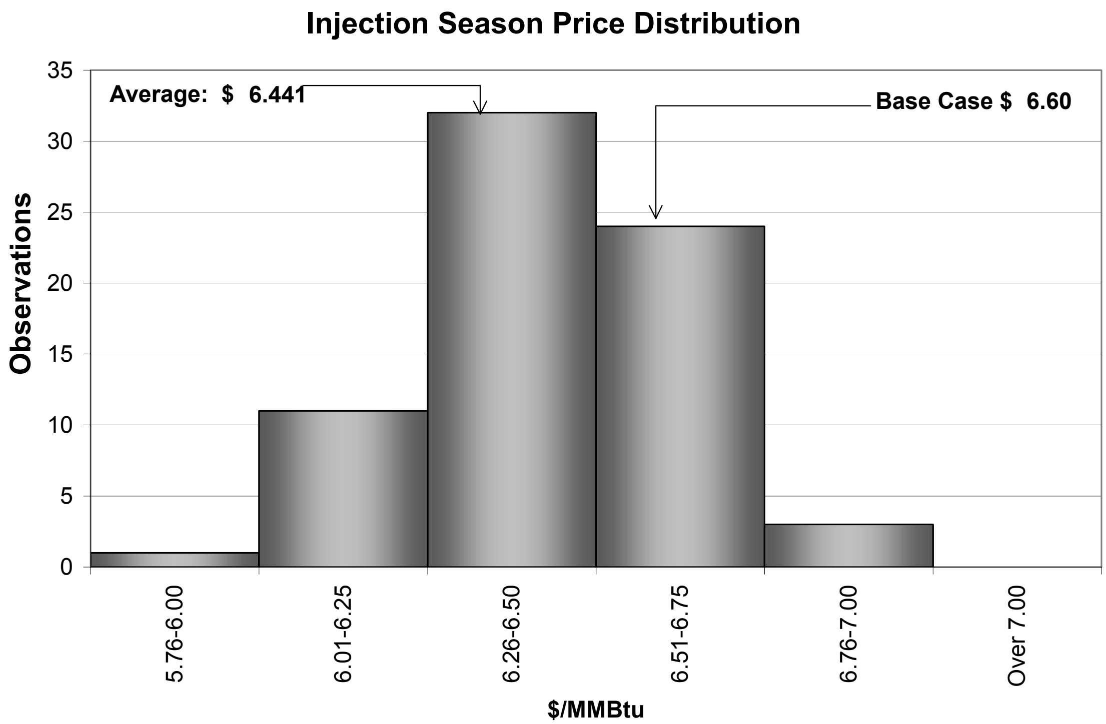
2) Fuel Switching

The ability of consumers to switch from natural gas to other fuels is a key element influencing demand response to price changes. A certain amount of gas-fired power generation and industrial boiler capacity that can easily switch between natural gas and alternative fuels. Generally, these customers switch from one fuel to another depending on natural gas price levels relative to the prices of other fuels. As a result, 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 affect a small reduction in demand. Demand is reduced as industrial consumers of natural gas shut down gas-fired applications and reduce output (demand destruction). Commercial and residential customers also respond to higher prices by reducing consumption, however this impact is generally delayed due to the regulatory structure of delivered gas prices to most residential and commercial customers.

Figure 3-2

Projected Impact of 2003 Summer Weather on Gas Prices at Henry Hub



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.

In the past, there has been a significant amount of fuel switching capability in the industrial and power generation sectors. In a report for the Gas Research Institute[1], EEA estimated that in 1985, about 26 percent of the total industrial natural gas market was dual-fuel capable, including 42 percent of boilers, and 28 percent of process heat applications. Most of this capability is believed to have disappeared since that time. Environmental regulations, dual fuel siting and permitting issues, and lower fuel prices throughout most of the 1990's discouraged maintenance of existing and investment in new dual-fuel fired capabilities. Our discussions with industrial gas users indicate that total dual-fuel capable capacity in the industrial sector is only about three to five percent of total natural gas consumption. In the absence of additional incentives to promote industrial fuel switching, we expect industrial fuel switching to remain at this level for the foreseeable future.

In contrast to the industrial sector, there still exists a significant amount of fuel switchable capacity in the power generation sector. Historically, between 40 percent to 50 percent of the

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[1] Energy and Environmental Analysis, Inc., <u>Fuel Switching Issues in the Industrial Sector</u>, December 1993, Gas Research Institute.

total operating hours for oil and gas steam boiler-fired power generation units have been switchable between gas and oil. This figure has declined somewhat due to environmental constraints on oil use and oil storage. EEA believes that 30 to 35 percent of total oil and gas steam boiler demand is realistically capable of switching from natural gas to oil today. Much of this capacity is located in the Southwest, while dual-fuel capacity in other regions, including California and the Northeast, has declined.

In the short-term, we would expect to see very little fuel switching in the residential or commercial sectors.

3) Oil Prices

Oil prices generally determine the natural gas price at which fuel switching for economic reasons occurs. Most of the potential natural gas fuel switching occurs between natural gas and residual fuel oil, or between natural gas and distillate fuel oil. Higher than normal oil prices increase the natural gas price at which it is economic to switch from natural gas to oil. The impact of oil prices on natural gas price volatility depends on the relative prices of the two fuels. If the price of natural gas is already substantially above or substantially below the price at which fuel switching is likely to occur, a change in oil prices will have almost no impact on natural gas price volatility. However, when oil prices are generally competitive with natural gas prices, the potential to switch from one fuel to the other tends to dampen natural gas price volatility.

4) Natural Gas End-Use Demand Growth Trends

In the long-term, economic growth is expected to have a significant impact on demand volatility, leading to a potential increase in price 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. The growth in power generation load is also expected to increase daily demand volatility. The majority of the new natural gas power generating stations will not serve as baseload sources of power. Instead, they will cycle on and off, operating as the marginal sources of electricity supply. This will lead to large day-to-day swings in natural gas demand.

5) Speculative Interests

As part of this study, 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 to evaluate the impact of trading activity by speculators and hedge funds on gas market prices. The results of this analysis are discussed more fully in Section 3 of Chapter 1 of the study results. We found that large price movements tend to increase the activity of speculators and hedge funds that see volatility as a profit opportunity. When this occurs, technical trading can cause the market to diverge from the fundamentals, creating additional imbalances.

During periods of transition in the market, when market conditions are changing from a supply constrained market to a supply excess market, or market conditions are changing from a supply excess market to a supply constrained market, and the general direction of prices appears to be changing, we typically see large swings in the amount of open interest held by non-commercial traders. Our analysis of the price impacts of these trades strongly suggests that this shift is often one of the major drivers of major price changes, and contributes to short-term price volatility beyond the level indicated by the supply and demand fundamentals.

Natural Gas and Power Generation Infrastructure Trends

1) Natural Gas Storage Usage Trends

In the traditional natural gas market, storage has been used to balance production and end-use demand, and as a substitute for pipeline capacity. In its most basic sense, storage is used to balance the patterns of gas production and gas demand. Storage is the primary source of swing supply during periods of higher than average annual demand, and is the primary source of swing demand when end-use demand is lower than the annual average demand. Hence, the level of available natural gas in storage has a direct impact on natural gas price volatility. The ability to withdraw varying amounts of gas from storage in order to meet changes in natural gas demand acts to minimize the need to use price to constrain demand, hence reducing natural gas price volatility.

Market area storage capacity has also traditionally been used as an alternative to pipeline capacity. When located in or near a market area, storage customers can use storage to meet peak demand rather than contracting for additional pipeline capacity. This allows contracted pipeline capacity to be used at a higher annual load factor, which reduces the per unit throughput cost. This in turn lowers the average cost of long-haul pipeline capacity[2] and reduces citygate price volatility by minimizing pipeline capacity constraints during peak usage periods.

Natural gas storage has also become an important tool for price arbitrage and hedging to manage and profit from gas price volatility. Gas can be injected into storage when prices are low, and withdrawn 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 used for price arbitrage both on a seasonal basis, as well as a short-term (daily, weekly, or monthly) basis. The use of natural gas storage for price arbitrage tends to dampen price volatility.

The recent growth in natural gas price volatility, combined with improvements in high deliverability storage technologies is expected to result in an increase in investment in storage capacity, particularly for high deliverability storage.

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[2] Under current FERC policy, there is a strong presumption for "straight fixed-variable" rate design (SFV) for regulated firm transportation recourse service. Under this rate design, the large fixed costs of pipeline capacity are recouped through monthly demand charges, which do not vary with throughput. If load factors are increased, the "per unit" cost of transportation declines.

2) Pipeline Capacity Investment Trends

In certain markets, natural gas pipeline constraints can be the largest factor contributing to natural gas price spikes. For example, pipeline capacity into New York City has been constrained during peak demand periods for several years, and appears likely to remain so for the foreseeable future. Factors that either promote or inhibit pipeline construction in areas of the country facing pipeline constraints will have a significant impact on future price volatility in these markets. Recent high natural gas prices are stimulating investment in pipeline capacity to bring natural gas to market from supply areas such as the Powder River Basin, and the Alaskan and Canadian Arctic regions.

3) Power Generation Market Conditions

Conditions in the power generation market play a major role in determining the amount of natural gas price volatility. The power generation sector tends to have a moderating influence on natural gas price volatility when:

- Natural gas fired generation provides the marginal source of power, and there is sufficient fuel switching capacity, or
- When enough excess generating capacity exists to allow generators to switch away from natural gas when prices increase and switch back when prices decrease.

However, when the power generation sector is capacity constrained, and no alternatives to gas-fired generation exist, power generators are willing to pay very high prices for natural gas. Under these conditions, the power generation sector tends to exacerbate natural gas price volatility. In particular, merchant generation capacity will continue to burn natural gas at any price, as long as electricity prices keep pace with gas prices.

Power generation demand is the fastest-growing segment of the gas market and will continue to provide the greatest increment of gas demand for the next decade. Power generation demand growth will dramatically affect operating conditions on the natural gas pipeline network. Because of the large amount of gas consumed at a power plant and the rapid and sometimes unanticipated changes in the hourly rate of consumption, gas-fired power plants have the potential to cause significant swings in the operating pressures and line pack on a pipeline. These changes will increase the need for storage facilities and other means for managing demand fluctuations.

Natural Gas Supply Trends

1) Frontier Gas Production

Much of the growth in natural gas supply over the next 20 years will come from development of frontier regions, including Arctic and eastern Canadian offshore areas. Reliance on frontier gas resources will tend to increase natural gas volatility relative to other supply sources due to the following characteristics of frontier supplies:

- Frontier projects generally require very large up-front investment, but feature very low incremental costs thereafter. As a result, there is a stronger than average incentive to maintain maximum production levels from frontier projects. Also, the price at which a production shut-in would occur is typically lower than for conventional resources. This tends to decrease short-term supply response to price.
- Frontier gas production often results in large increases in baseload gas supply into specific regions. If there is no accompanying increase in storage capacity, increases in volatility can result, particularly during summer months when demand is insufficient to fully utilize the level of gas produced. The resulting glut of excess natural gas requires large price movements to restore the balance between supply and demand. Such price movements can be minimized if sufficient storage capacity is available to absorb the excess production during the summer.
- Frontier projects come on-line in much larger than average increments. For example, the Alaska Gas Pipeline may bring as much as 4.0 Bcf per day (Bcf/d) into North American markets, primarily on the West Coast and in Chicago. The very large increment is likely to overwhelm available pipeline and storage facilities in these markets for at least the first few years of the project life, leading to increased transportation constraints and higher price volatility.

2) LNG Imports

There are a number of major LNG import facilities currently on the drawing board. If and when they are built, the facilities will have a significant impact on natural gas prices and price volatility. The impact of new LNG import capacity on volatility will depend largely on how the new facilities are utilized. If utilized at a very high load factor, the impact of an increase in LNG imports on price volatility will be similar to the impact of growth in frontier production, with potential increases in upward price volatility. The increase in supply should result in lower overall prices, but high load factor deliveries will focus more of the day-to-day swings in gas demand on domestic production sources, potentially increasing price volatility. The alternative scenario, in which LNG supplies seasonal loads, could reduce both overall price levels and seasonal price volatility.

3) Changes in Production Trends

Production patterns tend to change over time as production from a specific area increases and then declines, and as new production regions increase in prominence. As a result, there is a constant shift in the need for transportation and storage assets to match production and demand. The level of price volatility in end-use markets will be heavily influenced by the timing of new pipeline and storage investments needed to respond to the shifting production trends. Factors that delay pipeline and storage investment will tend to increase price volatility, while factors that promote investment should act to reduce volatility.

4) Development of New Storage Technologies

The majority of the new gas-fired power generation capacity that is likely to be developed in the future will be located near urban areas experiencing growth in power demand. These facilities represent attractive marketing opportunities for developers of high deliverability storage. However, the potential sites for developing high deliverability storage using current technologies are limited to a handful of regions with appropriate geology. Storage developers are aggressively pursuing alternative technologies that can be applied independent of the geological constraints that currently limit storage development. Successful implementation of these new technologies will reduce the impact of new power generation demand on gas price volatility.

3.2.2 Review of Natural Gas Market Responses To Price Behavior

In an efficient market, prices must change to correct imbalances of supply and demand. The degree of the imbalance and the speed with which producers and consumers are able to respond to relieve the imbalance both determine the magnitude of the change in prices.

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. Increasing deliverability requires new drilling activity, which takes three to nine months to have any significant effect on available supplies. 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 required for 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 initially very capital intensive, with relatively low marginal lifting costs. Even at low prices, most wells remain economic to produce, 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 invest 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, the life of the producing asset, which ranges from three to twenty years, determines the investment cash flow. Price expectations over this extended time frame will determine investment in new production.

Consumer Response to Price Changes

Consumers' responses to price changes vary by type of customer and by application. In the short-term, traditional residential and commercial gas customers show very little price elasticity. These core customers adjust demand principally in response to external factors such as weather and economic activity. Such customers provide little short-term demand response.[3] While under very high gas price conditions, there is a limited response due to thermostat turn-back or other conservation measures, 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.

Large industrial and power generation customers with dual-fuel capability[4] can respond to price changes by switching fuel sources. Customers switch fuels based upon the relationship between the gas price and the alternative fuel price (generally distillate or residual fuel oil).[5] However, once all of the easily switched customers are "off gas," the overall price elasticity of gas demand is significantly reduced.

Other than fuel switching, the industrial sector's response to increasing gas prices is to reduce 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 often offset by increases when gas prices fall again. New and more efficient equipment will not be removed 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 fundamentally limited to changes in industrial output. Even for those gas-intensive industries, such as ammonia, methanol, aluminum, steel, etc., 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 high gas prices are needed to change output significantly.

The power generation segment of the market can respond to gas price changes by shifting the dispatch of generating units. If gas prices fall, natural gas-fired generation can displace oil or coal units. If 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 the marginal generation and is dispatched only after virtually all other sources of capacity are tapped. As a result, gas-fired power generation does not provide a significant demand response in a tight supply 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.

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3 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 R/C sector demand was reduced by an estimated 5 to 7 percent. However, the demand reduction was a combination of the "price" response and "good- citizen" behavior in response to governmental calls for action. Economic literature has yet to definitively identify the magnitude of the price response.

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

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

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

As prices decline, we would also expect to see an increase in the gas processing extraction of natural gas liquids further reducing dry gas brought to market.

Natural Gas Storage and Transportation Infrastructure Response to Price Changes

Energy infrastructure constraints -- particularly on natural gas pipeline capacity and electricity generation and transmission capacity -- have been one of the key causes of recent price volatility in major markets. In the last several years, both California and New York City have experienced periods in which electricity and natural gas demand have exceeded the available power generation capacity and natural gas pipeline capacity, respectively. When use of these physical assets approaches capacity, prices tend to increase, sometimes very rapidly, reflecting 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 either demand growth or (in the case of some natural gas pipelines),with 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, where return on (and of) investments in natural gas pipelines and power generation capacity is no longer guaranteed via regulated rates of return.

When excess capacity exists, prices tend to be more stable. Additional supply is available at only modestly higher prices to respond to increases in demand. Natural gas, unlike electricity can be stored economically. About 50 percent of the total natural gas consumed on a peak day, and about 30 percent of total winter (November through March) demand is met with natural gas injected during the summer months. In addition, an increasing amount of short-term natural gas demand volatility is being met from high deliverability storage. As a result, natural gas price volatility is moderated by storage injection and withdrawal behavior.

However, a number of other factors impact injections and withdrawals. Most LDCs in cold weather climates rely on storage to meet winter season and peakday loads. LDC gas supply plans rely on target levels of storage at different points in the season. Moreover, tariff penalties and ratchets can limit the flexibility needed to optimize storage economically. Nevertheless, implementation of storage management programs and the development of high-deliverability storage provide a significant physical hedge, and act to mitigate daily and seasonal price volatility.

3.2.3 Impacts of Current Market Conditions on Future Energy Markets

The current liquidity crises among energy companies (including marketers and power generators) will have continuing implications for future natural gas liquidity and price volatility.

- The reduction in the liquidity of forward markets makes it much more difficult for LDC end-users to efficiently hedge price volatility risks. If the situation persists, the costs of hedging will increase substantially, and LDCs will face increased risk of prudence review and disallowance of costs.
- The loss of market transparency reduces the efficiency of the market. LDCs holding gas purchase contracts that are priced at the index price may be forced to change their practices. This could also increase the risks of prudence review and disallowance of costs.
- Equity and credit market conditions increase the costs of energy infrastructure development and increase the likelihood that energy markets will remain tight, thereby increasing prices and price volatility.
- General public distrust of energy markets and energy companies makes it more difficult for the gas and electricity industries to communicate with consumers and regulators.

3.2.4 Impact of Regulatory Structure on Price Volatility

Most of the market factors that lead to price volatility existed prior to the deregulation of the natural gas industry. However, because regulations restricted price movements, regulations were also needed to allocate natural gas supplies. This was accomplished through provisions for interruptible service, and via curtailment policies and procedures for firm loads. The unintended consequence was restricted market growth and creation of long-term gas scarcity and shortages.

Over the last twenty-five years, deregulation has generally eliminated the inefficiencies of the fully regulated market. However, the current period of price volatility and perceived market abuses can also be tied to the deregulation trend. The challenge for the industry is to understand the factors that contribute to volatility and to develop practical strategies to address its negative effects, while preserving the consumer efficiency benefits that market forces provide.

3.2.5 Key Findings Regarding Factors Influencing Recent Trends in Natural Gas Price Volatility

Natural gas has exhibited particularly large increases in price volatility. The increase in gas price volatility has three primary causes:

- Supply-demand fundamentals – Post-1999, there has been virtually no underutilized supply capacity available to respond to demand increases driven by weather. At the same time gas requirements for power generation, which can fluctuate rapidly with the demand for electricity, have increased significantly. The magnitude of the short-term demand response to changes in gas prices is relatively small. As a result, large movements in market prices have been needed to balance gas supply with demand.

- Effects of commodity trading techniques (Technical Trading) on short-term prices – All commodities traded, whether in exchanges or "over-the-counter," exhibit short-term volatility that can be attributed to short-term imbalances in buy-sell orders from speculators in financial markets. This effect can be seen empirically in the natural gas futures market and the Henry Hub "cash market" price. The impact of these forces on the Henry Hub reference price sends ripples through cash prices throughout the North American Market.

- Market imperfections – Market imperfections, such as imperfect information or asymmetric information[6], result in price movements. In the natural gas market, a lack of liquidity or concentration of trades in the hands of a limited number of large market participants added to volatility in various regional markets.

Of these three factors, the tightening of the overall supply-demand balance and the limited size of the demand response to price changes accounted for the vast majority of the volatility in gas prices since 2000.

Gas industry restructuring that has continued since the passage of the Natural Gas Policy Act (NGPA) in 1978 – and the implementation of restructuring embodied in decisions made by regulators – contributed to the large increase in gas price volatility. Restructuring of the gas industry increased the incentive for efficiency improvements and cost cutting in a manner that reduced the amount of underutilized supply capability available to moderate volatility.

The reduction in the prevalence of long-term contracts and limited infrastructure investment in facilities that could moderate price volatility resulted in growing volatility in gas prices, particularly in the populous Northeast United States. Increased reliance on spot gas purchases ensured that volatility in the commodity market was transferred to consumers. Restructuring of the natural gas industry was rooted in a philosophy that the goal of economic efficiency was the primary objective. As a result, policies and implementation promoted the transfer of market price signals to gas producers and purchasers as quickly as possible. The price signals transferred to consumers increased volatility seen by market participants. Distributors were often discouraged by regulators, at the risk of economic penalties, from contracting for additional gas transportation capacity or entering into long-term, fixed price supply contracts. Natural gas wellhead deregulation and the elimination of production prorationing promoted an increase in gas production utilization and a reduction in any overhang in deliverability. As a result, no short-term supply capability capacity reserve was available to satisfy short-term increases in demand, thus increasing price volatility.

With little reserve supply capability or delivery infrastructure, imbalances in the gas market were thrust upon the demand-side for the response needed to bring the market into balance. However, only a limited number of natural applications can easily switch to an alternative energy source in the short-term. Stricter environmental and land use policies and the lack of economic incentive or regulatory requirements for new independent power plants discouraged more dual fuel capable power generating units, which would moderate volatility, from being constructed. Despite periods of relatively high gas prices in recent years, the amount of electricity generated with gas grew by more than 62% since 1997 while the amount of electricity generated with oil in 2002

[6] Asymmetric information refers to conditions where one party has information regarding market conditions that is not available to other parties in the same market.

was 38% below the 1989 level. Developers of power generation projects often eliminated plans for dual-fuel capability to obtain permits for construction. In total, the percentage of gas applications that have a demonstrated capability to burn alternative fuels has declined significantly since the late 1980s. ***With limited fuel flexibility and little reserve supply and delivery infrastructure, large price movements are inevitable.***

3.3
Relationship Between Natural Gas Prices and Price Volatility

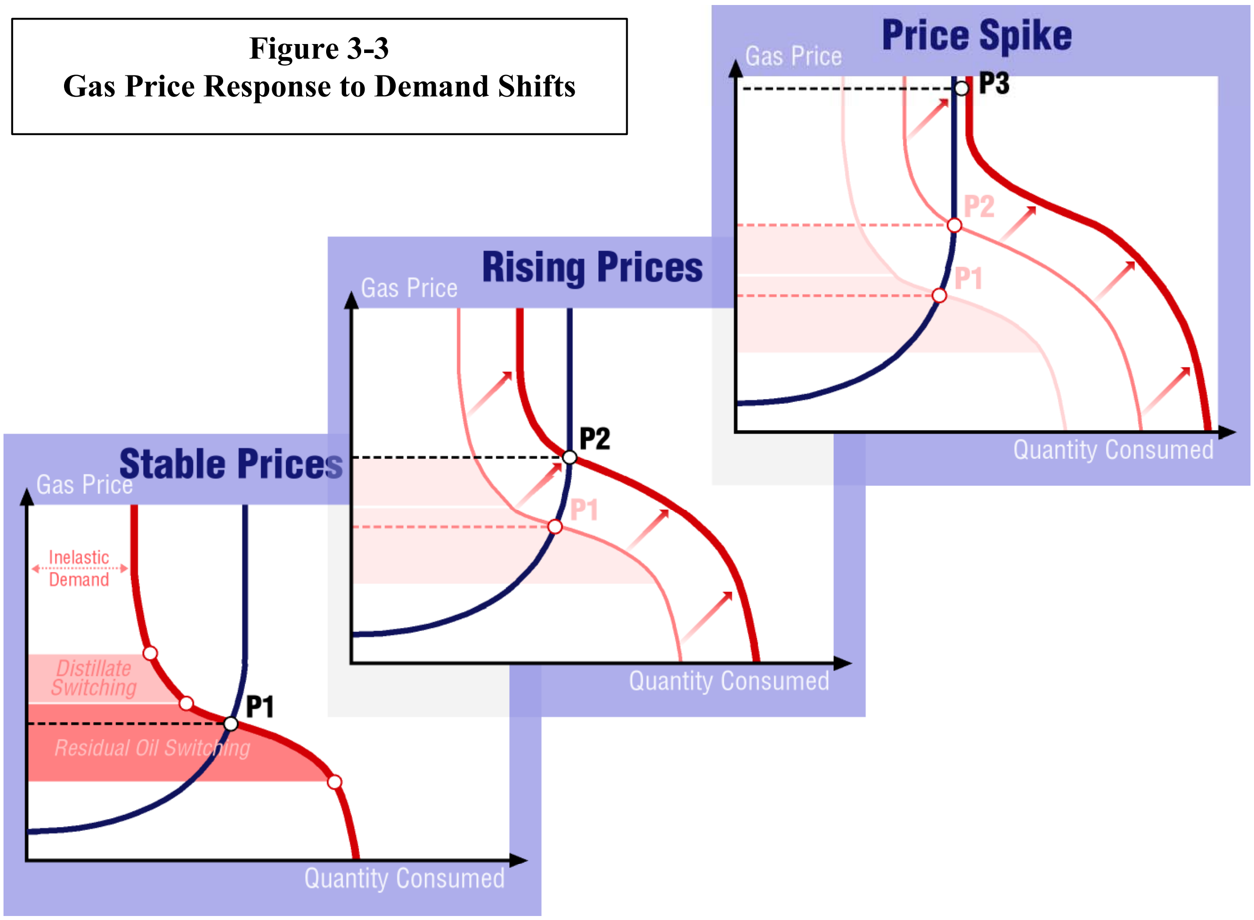
EEA has evaluated the fundamental drivers of daily price volatility in order to project future trends in natural gas price volatility. Conceptually, daily price volatility is a function of daily demand volatility, combined with supply constraints. In a tight market, changes in daily demand are expected to have a bigger impact on prices when significant alternative sources of supply are available. This chapter discusses the conceptual background for this assertion, and summarizes the results of a statistical analysis of the historical data that quantifies the relationship under the current market structure.

3.3.1 Conceptual Relationship Between Price and Volatility

As we have discussed at length in earlier volumes of this study, natural gas price volatility is substantially greater today than it has been in the past. We have discussed many of the factors behind this shift. However, we believe that the predominant cause of the increase in volatility is related to the current tightness in the supply/demand balance. Figure 3-3 illustrates this relationship, showing the impact of a tightening of natural gas markets on the response of price to changes in demand.

As demonstrated 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 switchable capacity has shifted 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.

Figure 3-3
Gas Price Response to Demand Shifts



3.3.2 Statistical Relationship Between Price and Volatility

To quantify the price/volatility relationship, we conducted a statistical review of price and price volatility data for a number of different natural gas market centers, including Henry Hub, Katy Hub, Chicago, Columbia Appalachia, Transco Zone 6, New York, and PG&E Citygate. We used the monthly average natural gas price as the measure of market tightness and average annualized return[7] for each month to represent price volatility. Figure 3-4 illustrates the time series data for Henry Hub for these two variables.

Note that this figure shows a period of very high price volatility between October and December of 2001, during a period of relatively low and stable natural gas prices. This relationship, which is observed consistently across natural gas prices in different locations, is believed to reflect the impact on day-to-day natural gas prices of the Enron collapse, and the associated adjustments in gas market trading operations on day-to-day natural gas prices.

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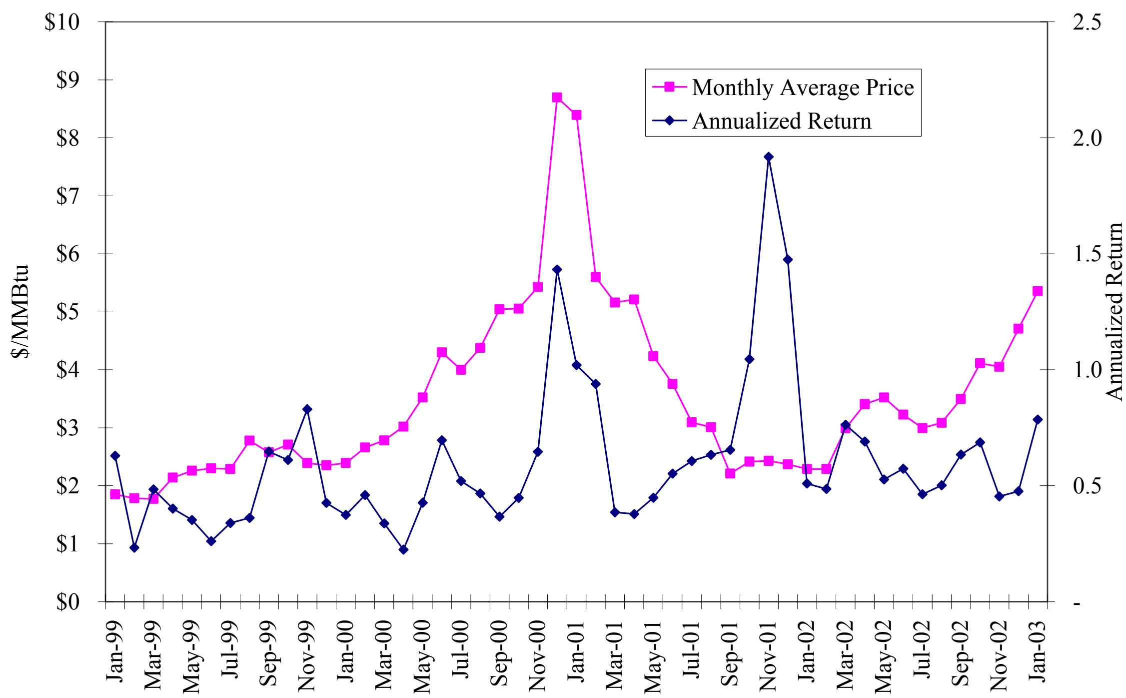
7 Annualized return is a relative measure of volatility, hence is not dependent on the actual level of prices.

Figure 3-4

Henry Hub Price and Price Volatility



The results of the statistical review indicate that when the time period of the Enron collapse is accounted for, annualized returns are expected to increase more rapidly than prices when prices are increasing, and decrease more rapidly than prices when prices are falling.

Table 3-1

Statistical Relationship Between Natural Gas Prices and Price Volatility

	Intercept	Price Coefficient	Enron Collapse Coefficient	Adjusted r-square
Henry Hub	0.237	0.086	1.034	0.635
Katy Hub	0.244	0.095	1.164	0.604
Columbia, Appalachia	0.212	0.091	1.062	0.601
Chicago Citygates	0.060	0.149	1.174	0.528
PG&E Citygate	0.283	0.166	1.185	0.347
SoCal	0.300	0.139	1.129	0.383
Transco Zone 6 New York	(0.152)	0.299	1.044	0.380

In the supply regions (Henry Hub, Katy Hub, and Columbia Appalachia), a $1.00 increase in natural gas price is estimated to account for about a 10 percent increase in annualized price volatility. To put this in perspective, a one dollar increase in natural gas prices at Henry Hub from $4.00 to $5.00 would be expected to increase the average daily price movement at Henry Hub from +/-$0.12 to +/-$0.18 per MMBtu.

Price volatility generally increases more rapidly in market centers closer to the major end-use demand centers due to the volatility of natural gas transportation rates into key markets. In Chicago, a $1.00 increase in natural gas price is estimated to account for about a 15 percent increase in annualized volatility. In New York, a $1.00 increase in natural gas price is estimated to account for about a 30 percent increase in annualized volatility. Detailed results of this analysis are provided in Appendix E.

3.4
Future Energy Price Volatility

In the previous sections of this report, we identified the key factors that will influence natural gas price volatility in the future. Most of these factors are highly interrelated with overall conditions in natural gas markets. In order to evaluate future volatility, we have used EEA's long-term natural gas market forecast (produced with the GMDFS) as a basis for projecting future natural gas market and price trends. Our forecast indicates that natural gas markets will be very tight for the foreseeable future, with aggressive demand growth and supply growth just sufficient to meet demand. As a result, we expect both long-term natural gas prices and shorter-term natural gas price volatility to remain high.

The key drivers of the market include:

- Long-term demand trends, including changes in seasonal and daily demands resulting from changes in the composition of the market, are likely to increase short-term natural gas price volatility, as well as keeping natural gas prices relatively high in the longer-term.
- Supply trends, particularly the shifting of traditional supply sources and growth in non-traditional supply sources such as LNG imports and Arctic gas, are generally expected to increase short-term natural gas price volatility due to a decline in supply flexibility, while moderating gas price levels in the longer-term by bringing additional sources of natural gas to the market.
- Prices and price volatility will be significantly influenced by the amount of infrastructure investment, including investments in natural gas pipeline and storage capacity, as well as power generation capacity.

The forecast is also based on a series of assumptions concerning overall market structure. Key assumptions concerning market structure include:

- A continuation of current regulatory status in both the natural gas and electricity industries.
- Continuation of facility investment criteria, resulting in investments only when the current market conditions indicate that the investment will be profitable after new capacity is installed.

EEA's forecast indicates that natural gas price volatility can be expected to increase in the next several years relative to the levels seen in the recent past, before stabilizing at a relatively high level for the foreseeable future. The factors and rationale behind this conclusion are presented below.

3.4.1 Impact of Demand Trends on Prices and Volatility

Growth in Demand

Table 3-2 shows EEA's forecast of average and peak day demand by end-use sector for 2000 through 2020. The EEA Base Case projects an increase in U.S. Lower-48 end-use natural gas demand[8] from 22.8 Tcf, (62.4.0 Bcf/d) in 2000 to 30.6 Tcf (83.8 Bcf/d) by 2020, resulting in an increase in average daily demand of 21.4 Bcf/d. As shown in this table, about two thirds of the growth in demand is expected to occur in the power generation sector, with the residential and commercial sectors accounting for most of the remaining growth.

The growth in demand is also projected to result in a growth of coincident daily peak U.S. demand[9] from about 104.1 Bcf/d to 135.7 Bcf/d - a gain of 31.6 Bcf/d. This means that the difference between *coincident* peak demand and *average* demand is expected to grow by 10.2 Bcf/d.

Fuel Switching Trends

In the past, there has been a significant amount of fuel switching capability in the industrial and power generation sectors. In a 1993 report for the Gas Research Institute[10], EEA estimated that in 1985, about 26 percent of the total industrial natural gas market was dual-fuel capable, including 42 percent of boilers, and 28 percent of process heat applications. While much of this physical capability is still in existence, the majority of these facilities burn natural gas, and are able to switch to fuel oil for only limited time periods, if at all. Our discussions with industrial gas users indicate that total dual-fuel capable capacity in the industrial sector is only about three to five percent of total industrial natural gas consumption. In the absence of additional incentives to promote industrial fuel switching, we expect industrial fuel switching in existing applications and technologies to remain at this level for the foreseeable future.

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8 End-use gas demand includes residential, commercial, industrial and power generation demand, but excludes pipeline fuel and lease and plant fuel.

9 Coincidental Peak Day Demand represents demand on the single highest demand day for the Lower-48 United States for the year, e.g., total gas demand and gas demand by end-use sector on January 28, 2005.

10 Energy and Environmental Analysis, Inc., Fuel Switching Issues in the Industrial Sector, December 1993, Gas Research Institute.

Table 3-2
Contribution by Sector to
Coincident Lower-48 U.S. Peak Demand

	Sector	Annual End-Use Demand (bcf)	Average Demand (bcf/day)	Growth in Average Demand (bcf/day)	Contributio to Peak (bcf/day)	Growth in Contributio to Peak (bcf/day)	Peak/ Average Ratio	Percent of Peak
2000	Total	22,790	62.4		104.1		1.67	100%
	Residential	5,092	14.0		36.1		2.59	35%
	Commercial	3,325	9.1		19.9		2.19	19%
	Industrial	8,748	24.0		27.6		1.15	26%
	Power Generation	3,957	10.8		13.1		1.21	13%
2005	Total	22,890	62.7	0.3	106.2	2.1	1.69	100%
	Residential	5,256	14.4	0.4	40.0	3.9	2.78	38%
	Commercial	3,325	9.1	0.0	20.7	0.8	2.28	20%
	Industrial	8,104	22.2	-1.8	25.9	-1.7	1.17	24%
	Power Generation	4,455	12.2	1.4	13.8	0.7	1.13	13%
2010	Total	26,033	71.3	8.9	120.1	15.9	1.68	100%
	Residential	5,590	15.3	1.4	42.2	6.2	2.76	35%
	Commercial	3,706	10.2	1.0	22.5	2.6	2.21	19%
	Industrial	8,562	23.5	-0.5	27.2	-0.3	1.16	23%
	Power Generation	6,352	17.4	6.6	19.4	6.3	1.11	16%
2015	Total	28,713	78.7	16.2	128.2	24.0	1.63	100%
	Residential	5,793	15.9	1.9	43.6	7.5	2.75	34%
	Commercial	3,906	10.7	1.6	23.7	3.8	2.21	18%
	Industrial	8,857	24.3	0.3	28.2	0.6	1.16	22%
	Power Generation	8,209	22.5	11.6	25.0	12.0	1.11	20%
2020	Total	30,602	83.8	21.4	135.7	31.6	1.62	100%
	Residential	6,047	16.6	2.6	45.6	9.5	2.75	34%
	Commercial	4,173	11.4	2.3	25.4	5.5	2.22	19%
	Industrial	9,133	25.0	1.1	29.0	1.5	1.16	21%
	Power Generation	9,227	25.3	14.4	28.1	15.0	1.11	21%

Source: EEA's Gas Market Data and Forecasting System January 2003 Base
Note: Daily gas demands are calculated at each of over 100 market nodes in the Lower
Peak values shown here are for one day each year of highest gas demand across
Daily temperature profiles used for calculations are a synthetic
representing 30-year heating and cooling degree "normals" for each

Dual Fuel Industrial Boilers

EEA estimates that natural gas consumption in steam boilers accounted for about 15 percent (1,300 Bcf) of total industrial natural gas consumption in 2000. 42 percent of that consumption is in dual-fuel capable boilers. However, we estimate that only about half of the consumption of dual-fuel capable boilers would be switchable to an alternative fuel in today's market environment due to environmental and operational constraints.

In the future, we expect the dual-fuel boiler population to be stable, with no growth for the foreseeable future. In addition, it is more economical to use natural gas in direct end-uses than to use it to generate steam in a boiler that then feeds steam-fired end-use equipment. As a result, industrial watertube boiler sales have been declining since 1976, punctuated with a small rebound around 1990. We expect sales to continue on a downward trend through 2010, with sufficient sales to offset retirements.

Fuel Switching in DG and CHP

New industrial technologies, including Distributed Generation (DG) and Combined Heat and Power (CHP) can be installed with dual-fuel capabilities. However, additional capital costs, warranty concerns and environmental costs associated with adding dual-fuel capability to a natural gas system are expected to limit penetration of dual-fuel capable systems.

Currently, small-scale industrial and commercial DG/CHP installations are largely single-fuel systems. The economics of installing dual fuel capability in systems of less than 2 MW make penetration of any significant dual-fuel capacity in this market unlikely without fundamental changes in technologies or fundamental changes in the economic incentive structures.

There is more potential for dual-fuel capably systems for installations greater than 2-3 MW. New dual-fuel systems using natural gas in this size range will be combustion turbine-based. [11] However, emissions constraints and manufacturer warranty concerns limit operating CT/CC systems on oil.

An evaluation of the industry/DOE CHP Road Map objectives suggests that dual-fuel capable CHP capacity would account for 3.5 percent of total CHP capacity installed between 1999 and 2010. At this penetration level, dual-fuel capable CHP would increase from 1,993 MW in 1999 to 3,591 MW by 2010, and would account for about 640 Mmcfd, or about three percent of total industrial natural gas consumption by 2010.

Fuel-Switching in the Power Generation Sector

In contrast to the industrial sector, there still exists a significant amount of fuel switchable capacity in the power generation sector. Historically, between 40 percent to 50 percent of the total operating hours for oil and gas steam boiler-fired power generation units have been switchable between gas and oil. This figure has declined somewhat due to environmental constraints on oil use and oil storage. EEA believes that 30 to 35 percent of total oil and gas steam boiler demand is realistically capable of switching from natural gas to oil today.

However, future gas use in the power generation sector will occur primarily in new combined cycle and gas turbine facilities. Most of the new gas-fired power generation capacity is projected to have only limited fuel switching capability. We estimate that about 10 percent of current and

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11 Analysis of the 2000 HB CHP installation database shows that existing dual-fuel capacity that use natural gas as a primary fuel and operates 95% of the time or less on natural gas is comprised mostly of combustion turbines (CT) and combined cycled systems (CC).

planned CC and CT capacity is dual fuel capable. However our discussions with power generation industry and natural gas industry executives indicate that consumption of a fuel other than natural gas at existing and planned CT and CC units would be limited to less than five percent of the total hours of operation. We expect this share to increase over time as the economics of fuel switching become more compelling, and turbine technologies improve to reduce operational concerns with fuel switching. By 2010, we expect 20 percent of combined cycle and gas turbine units to be dual-fuel capable.

Total Fuel Switching Potential

Table 3-3 shows the total estimated fuel switching potential in the EEA Base Case. The estimate of technical potential is based on an evaluation of the physical capability to switch from natural gas to fuel oil or residual fuel. The estimate of available fuel switching potential reflects our projection of the amount of fuel switching potential that might actually be available in the market given the current and projected market conditions and regulatory environment.

Impact of Demand Trends on Price Volatility

EEA's analysis leads us to believe that the demand trends will tend to increase price volatility in a number of different ways.

1) The general growth in demand is expected to result in a very tight balance between supply and demand, leading to a high-price, high-volatility environment.
2) The growth in weather-sensitive load will increase demand response to changes in weather, increasing overall demand volatility. The absolute increase in weather driven demand increases the sensitivity of demand to changes in the weather, and is likely to result in an increase in weather related volatility.
3) The growth in the absolute spread between peak day demand and average demand will increase demand on storage and pipeline capacity to meet peak rather than average demands. This increase in requirements will reduce reserve margins on existing infrastructure, and require additional investments in new capacity. The higher utilization of capacity, and increased potential for capacity shortfalls is expected to increase price volatility.
4) 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 be operated as baseload sources of power. Instead, they will cycle on and off, serving as the marginal sources of electricity supply. This will lead to larger day-to-day swings in natural gas demand.

Table 3-3
Estimated Fuel Switching Potential In U.S. Natural Gas Markets

Projected U.S. Natural Gas Consumption (Bcf)

	2000	2005	2010	2015	2020
Total	**22,790**	**22,890**	**26,033**	**28,713**	**30,602**
Residential	5,092	5,256	5,590	5,793	6,047
Commercial	3,325	3,325	3,706	3,906	4,173
Total Industrial	**8,748**	**8,104**	**8,562**	**8,857**	**9,133**
Boilers	1,300	1,300	1,300	1,300	1,300
Process Heat/Other	6,618	5,824	6,112	6,267	6,323
CHP/DG	830	980	1,150	1,290	1,510
Total Power Generation	**3,957**	**4,455**	**6,352**	**8,209**	**9,227**
Steam Generation	3,403	2,049	2,605	2,980	2,917
CC/CT	554	2,406	3,747	5,229	6,310

Estimated Technical Fuel Switching Potential (Bcf)

	2000	2005	2010	2015	2020
Total	2,439	2,032	2,786	3,424	3,829
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Total Industrial	**682**	**707**	**734**	**757**	**793**
Boilers	546	546	546	546	546
Process Heat/Other	1,240	1,092	1,146	1,175	1,185
CHP/DG	136	161	188	211	247
Total Power Generation	**1,757**	**1,325**	**2,052**	**2,667**	**3,036**
Steam Generation	1,701	1,025	1,302	1,490	1,458
CC/CT	55	301	749	1,177	1,578

Estimated Available Fuel Switching Potential (Bcf)*

	2000	2005	2010	2015	2020
Total	**1,560**	**1,221**	**1,654**	**2,010**	**2,206**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Total Industrial	**341**	**353**	**367**	**379**	**397**
Boilers	273	273	273	273	273
Process Heat/Other	310	273	286	294	296
CHP/DG	68	80	94	106	124
Total Power Generation	**1,219**	**868**	**1,286**	**1,631**	**1,810**
Steam Generation	1,191	717	912	1,043	1,021
CC/CT	28	150	375	588	789

* Based On Status Quo

5) The growth in power generation gas demand is also likely to reduce the amount of potential fuel switching from gas to oil. In relative terms, the new capacity currently on the drawing board will have significantly less dual-firing capability than existing boiler units. In some cases, the new capacity will replace older existing boiler generators. In other cases, the high efficiency combined cycle units are expected to reduce the operating load factors for existing boiler generators. Even though these units might technically remain able to burn an alternative fuel, the price at which it becomes economic to burn the alternative fuel will increase, reducing economic fuel switching potential.

3.4.2 Impact of Supply Trends on Prices and Volatility

Like the long-term demand trends, the long-term supply trends are also expected to lead to an increase in price volatility. Natural gas supply will have to grow significantly to meet projected U.S. demand over the next two decades, and the balance between demand and supply is expected to remain very tight, which leads to a continuation of high prices and high price volatility. In addition, changes in the location of future natural gas resources are expected to reduce supply flexibility, which will generally increase volatility. These factors are discussed below.

Sources of Future Supply

In EEA's Base Case, production from existing supply sources in the Lower-48 will struggle to remain constant. EEA expects significant declines in the shelf of the Gulf of Mexico, the Mid-Continent, the San Juan Basin, and the Permian Basin. EEA expects that production from these areas will decline by 3 Tcf per year by 2020. Other regions, except for the Rockies and the deep Gulf, will show slight gains in production at best.

The declines in production from existing supply sources are mainly due to the lack of quality drilling prospects in the areas. Already, the North American gas market is experiencing declines in some basins. Recent historical production trends have shown significant declines in the shallow waters in the Gulf of Mexico and the Mid-Continent producing areas. Recent historical production has been fairly flat in the Permian and San Juan Basins. Gas producers have had to work harder to develop additional deliverability. In 2001, a banner year for drilling with well over 1,100 active rigs, producers completed nearly 22,000[12] gas wells, but increased deliverability by only about 1 Bcf/d in the U.S. In the adjacent years, when drilling activity was much lower, deliverability remained flat or declined. Producers are working harder in mature areas, but are developing less productive gas resources.

Growth in gas demand and declining productive capacity in mature producing areas will yield an increased reliance on new producing frontiers in the future. The EEA Base Case projects that in the future a much greater part of gas supply will come from “non-traditional” sources of supply including:

- Continued development of deepwater gas in the Gulf of Mexico.

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12 Source: Energy Information Administration, *Monthly Energy Review* (November 2002)

- Continued development of unconventional gas from the Rocky Mountains.
- Development of Mackenzie Delta and Alaskan gas.
- Significant development of Eastern Canada offshore gas.
- Development of LNG imports.

By 2010, supply from new producing regions will account for almost 10 Tcf or nearly one-third of North America's gas supply, and by 2020 new producing frontiers will account for nearly 17 Tcf or nearly one-half of North America's gas supply. Hence, much of the growth of the gas market over the next 20 years is likely to be sustained by development of currently untapped supplies from areas that are generally more remote from the consuming markets throughout North America.

Impact of Changing Supply on Price Volatility

Frontier Production

The major change in natural gas supply trends in the next twenty years will be the reliance on frontier gas resources to meet demand. Reliance on these resources tends to increase natural gas volatility relative to other more conventional supply sources due to several of the characteristics of frontier supplies. Most frontier projects can be expected to flow as close to capacity as is operationally possible, regardless of market conditions. Hence, changes in natural gas price are unlikely to have a significant impact on production from these projects.

Frontier gas production also can be expected to result in large increases in baseload gas supply into specific regions. If the ability to store gas or move gas out of the affected regions is not expanded accordingly, an increase in volatility within certain regions is likely to result. This is most likely to happen during summer months, when demand is insufficient to fully utilize the level of gas produced. Also, frontier gas entering markets in the large increments typical of this type of production is likely to overwhelm available pipeline and storage facilities in these markets for at least the first few years of the project life, leading to increased transportation constraints and higher price volatility.

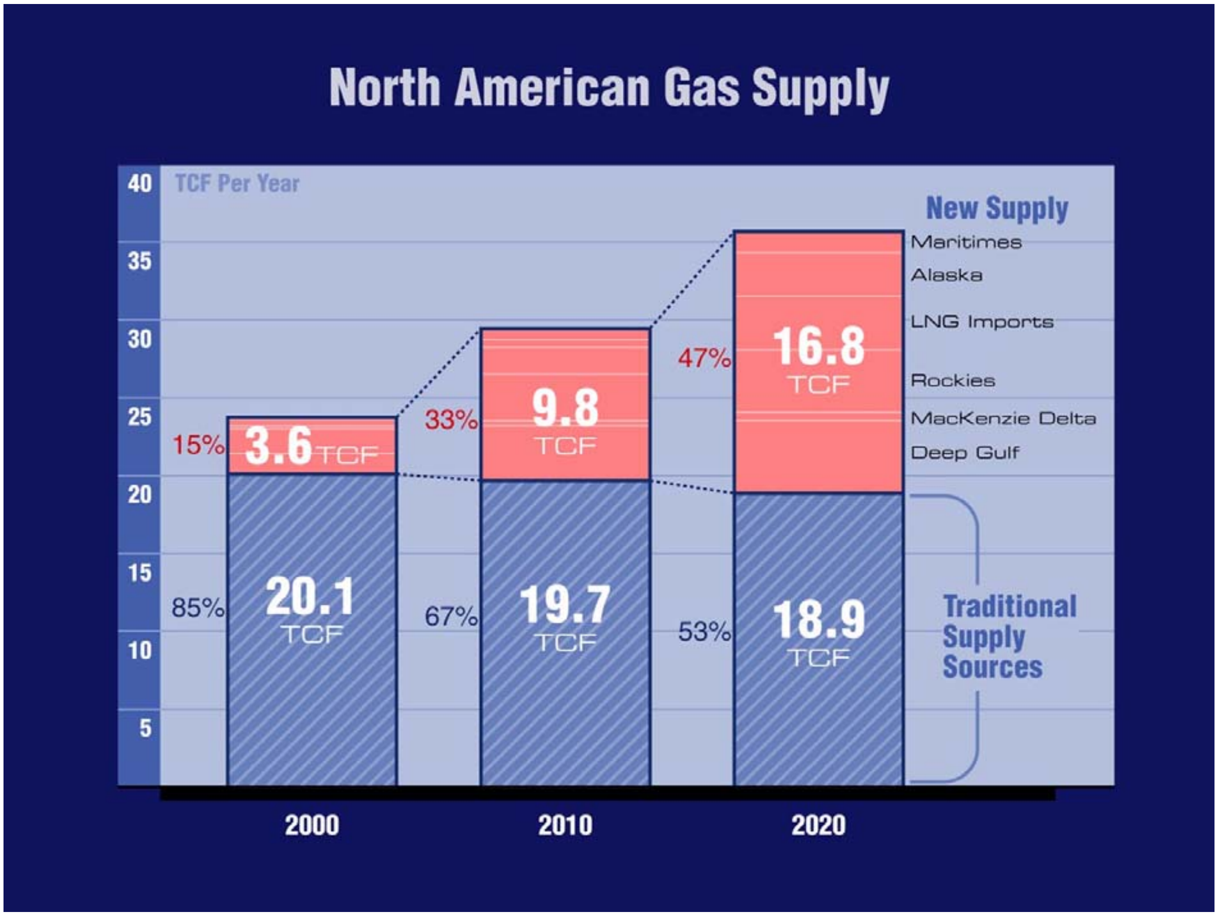
The large price movements that will be needed to balance supply and demand in this case can be minimized if sufficient storage capacity is available to absorb the excess production.

LNG

The impact on price volatility from the reliance on large volumes of LNG imports is somewhat more difficult to determine. There are a number of major LNG import facilities currently in the planning stages. The impact of new LNG import capacity on volatility will depend largely on what role the new facilities will play.

Figure 3-5

Reliance on New Supplies



In our view, the most likely scenario for LNG usage is to provide baseload gas supplies at a very high load factor. Current facility costs are sufficiently high to require baseload usage to recoup investment costs. If utilized at a very high load factor, the impact on volatility will be similar to the impact of frontier production, with potential increases in price volatility. However, if facilities can be constructed to meet seasonal or peak loads economically, and if sufficient international liquifaction and transportation capacity is built to create an active international LNG commodity market, the use of LNG would reduce seasonal price volatility.

LNG is also likely to be more sensitive to major price swings than frontier production. However, LNG is also subject to the vagaries of the international market. If markets in Japan or South Korea (or other markets) are willing to pay more than the North American market price, LNG will be diverted to these markets, increasing price pressure and volatility in the North American market. This occurred during the 2002/2003 winter, when LNG deliveries to the U.S. fell below expectations due to higher market prices for LNG in Asia.

3.4.3 Infrastructure Requirements

The changes in demand and supply trends will create the need for significant investment in new natural gas transportation and storage infrastructure.

- The overall level of demand growth will require expansion of the existing natural gas supply and transportation infrastructure.
- Changes in the location of supply will require shifts in transportation corridors to accommodate new flow patterns.
- Increases in seasonal natural gas demand will stimulate demand for seasonal storage capacity.
- The higher level of natural gas volatility provides incentives to develop storage to take advantage of natural gas price arbitrage opportunities.
- Operational changes in the nature of gas demand and transportation, including short-term fluctuations in demand in the power generation sector, and the growth of hub storage to meet operational requirements stimulates demand for high deliverability storage fields, such as salt dome storage and strategically located depleted field storage with operational flexibility.

The amount of investment in new facilities in response to these trends will have a significant impact on future price volatility. If liquidity concerns in the energy industry restrict investment in new facilities, or reregulation of the energy industry reduces potential profits associated with new investments, we could see significant increases in future natural gas and electricity price volatility. Trends in pipeline transportation requirements and storage requirements are discussed below.

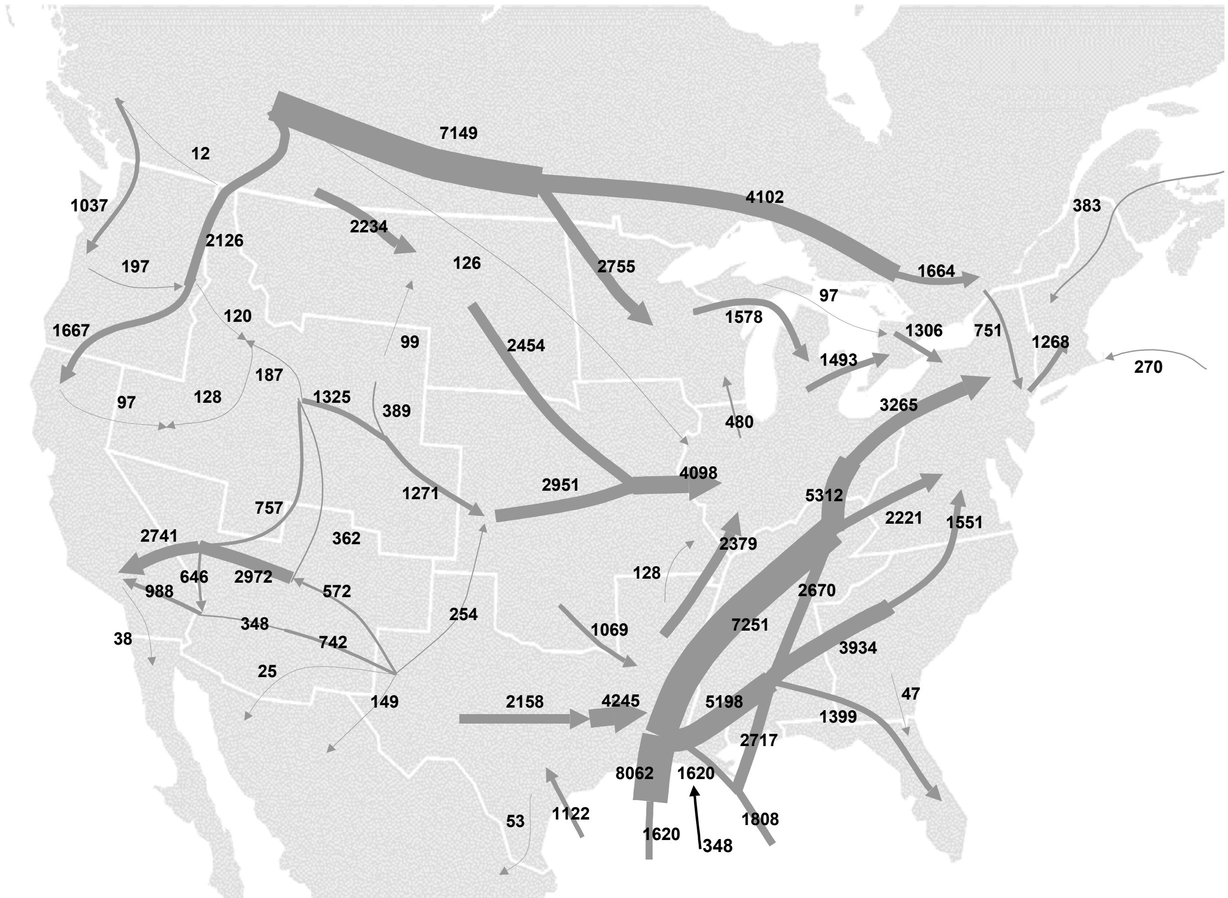
Pipeline Transportation Requirements

Most natural gas is produced in regions with limited natural gas demand and must be transported significant distances to the consuming market. By the end of the next decade, flow patterns of natural gas supply to natural gas markets will be about the same as they were in 2000. The most important supply areas will still be the Gulf of Mexico and Western Canada. However, new supply sources, such as Arctic gas, Eastern Canadian offshore gas and new LNG import terminals are expected to emerge. Flows from most of the mature producing areas will be in decline by 2020.

Figure 3-7 illustrates the expected change in natural gas flows between 2000 and 2020. Compared to 2000, flows will increase in 2020 by an additional 8.5 Bcf/d out of Western Canada, 3.0 Bcf/d out of Eastern Canada, 10.2 Bcf/d out of the Deep Gulf of Mexico, and 5.9 Bcf/d out of the Rocky Mountains. Flows from Western Canada include new supplies from Alaska and the Mackenzie Delta. Increased flow will also occur in coastal areas where new LNG import terminals are built or where there are expansions of existing LNG import terminals.

Figure 3-6

EEA Base Case - Average Flow in 2000 (MMcf/Day)



The changes in natural gas flows will require a significant investment in new pipeline and storage capacity. The amount of additional interregional pipeline capacity built by the year 2020 in EEA's Base Case is substantial. From 2000 to 2020, approximately 9.1 Bcf/d of additional pipeline capacity will be needed out of Western Canada, 3.2 Bcf/d from Eastern Canada, 6.6 Bcf/d from the Rockies, and 9.6 Bcf/d out of the deeper waters of the Gulf of Mexico. In addition to the increased pipeline capacity, nearly 9 Bcf/d of additional LNG terminal receipt capacity in various coastal locations will be needed.

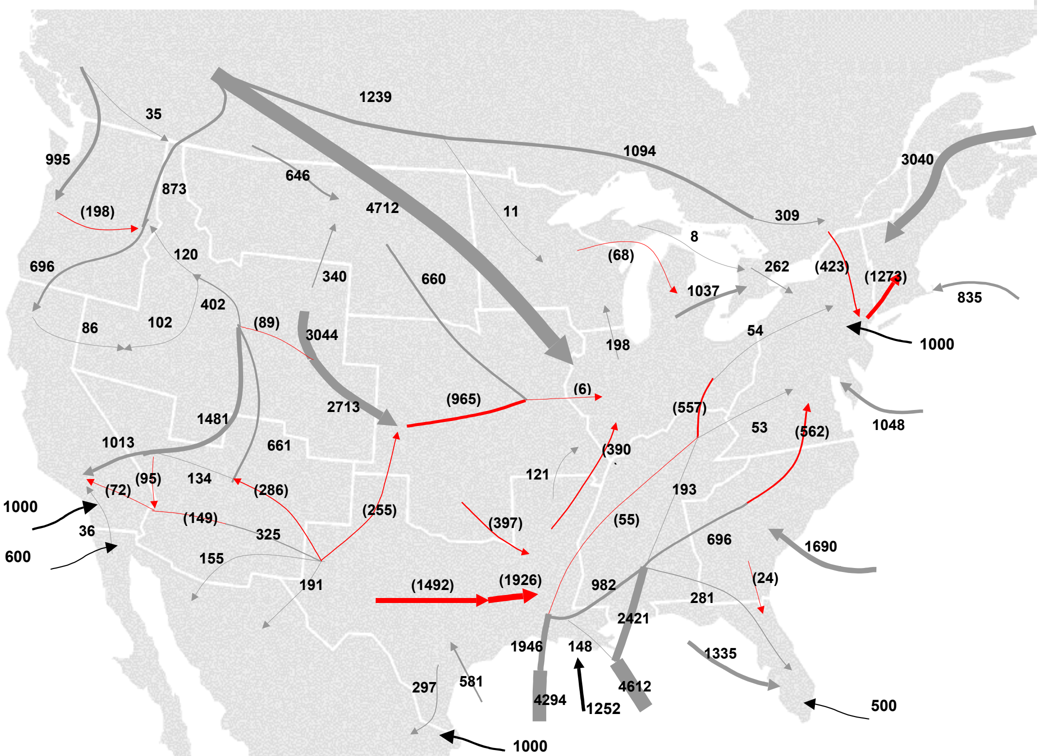
Along with major projects connecting new supply basins, there will be numerous pipeline projects to relieve local bottlenecks in market areas.

Many major supply corridors that exist today will not need expansion. For example, no increases are anticipated out of the Mid-Continent or Texas to the Northeast and Midwest. In addition, some transportation corridors will experience declining volumes. Flow from the South into New York and New England will be reduced by about 1.3 Bcf/d, as offshore gas from

Eastern Canada is imported into the United States. Flows out of Texas decline as production declines and local consumption grows. Flows out of the Mid-Continent to the East will decline by nearly 1 Bcf/d. The 2.7 Bcf/d influx of Rocky Mountain gas into the Mid-Continent will not offset declining production in the area, and therefore gas exports out of the region will decline.

Figure 3-7

EEA Base Case - Changes in Average Flow 2000-2020 (MMcf/day)



Storage

Storage is used to balance production and end-use demand. It reduces the need for additional pipeline capacity into a market when loads differ seasonally. Traditionally, natural gas pipelines or LDCs have owned most of the storage capacity directly, and employed it to meet cold weather load. As peak demand continues to grow faster (in absolute terms) than average demand, additional storage capacity will be required to balance seasonal demands and production.

Storage is also an important tool for price arbitrage and hedging to manage gas price volatility. Gas is bought and sold at 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 available to move gas between market centers. Gas can be injected into storage when prices are low, and withdrawn from storage when prices are high. Storage is used for price hedging on a seasonal basis as well as on a short-term (daily, weekly, or monthly) basis. On a seasonal basis, the arbitrage value of storage can be locked in by using the futures markets to hedge the future price of the gas put into storage.

Growth in storage capacity is likely to be one of the determining factors in moderating future price volatility. Seasonal storage capacity will be a key element in the infrastructure chain needed to bring frontier gas into U.S. markets. However, the cost of developing new storage facilities is closely tied to the market price of natural gas. While new technologies are reducing the amount of base gas required for injection into new storage fields, base gas still represents one of the largest cost elements of developing new seasonal storage facilities. As a result, the current high gas price environment is likely to curtail development of some seasonal storage capacity.

The high daily price volatility in the current environment does increase the potential value of high deliverability storage (typically salt cavern storage), and is likely to promote development of additional storage capacity of this type.

EEA is projecting an increase in North American storage working gas capacity of about 595 Bcf between 2002 and 2020. While this represents about 14 percent growth from existing levels, demand is projected to increase by 34 percent and peak demand is expected to increase by 30 percent over the same period. We understand that at least some storage developers believe our forecast to be overly optimistic, particularly in a high price environment with high base gas costs. As demand and production growth outpaces storage growth, the relatively slow increase in storage working gas capacity is expected to increase seasonal price volatility over time.

Operational Challenges

The current natural gas delivery system was built and optimized over decades to meet the peak-day requirements of firm service customers in the winter. However, two-thirds of the gas demand growth anticipated during the next two decades will come from power generation consumers. These loads are more variable and less predictable and they will require systems to be re-optimized to meet larger off-peak summer loads. Higher and more intensive swings in delivery volumes must be anticipated and managed.

Traditionally, local distribution companies (LDCs) were the only customers of interstate natural gas pipelines. Now, there is a mix of LDCs, marketers, power generators, producers, and end-users. Changes in operational procedures, communications, tariffs, and contracting will be needed, and more diverse pipeline services must be provided. Services offered must be more flexible. Technology improvements for expanding and managing delivery, such as real time measurement, must be added. These changes must be made without significantly degrading current service to the traditional heating load customers.

3.4.4 Forecast of Future Natural Gas Price Volatility

The combination of the increase in demand volatility, the decrease in supply flexibility, and the potential tightening of pipeline and storage infrastructure is expected to lead to a continuation of high natural gas prices, and high natural gas price volatility.

We have used two different approaches to project future natural gas price volatility. In the first, we have used EEA's forecast of future natural gas market trends to evaluate natural gas prices and seasonal gas price volatility for the 2003 - 2020 time period. This forecast includes an evaluation of seasonal price volatility, reflecting the impact of demand trends on peak demand, construction of pipeline and storage infrastructure, supply trends, and the overall balance between supply and demand. Our forecast includes monthly prices, hence the measure of price volatility from this forecast reflects a measure of seasonal price volatility, rather than the daily price volatility evaluated in much of the rest of this study. We have also used the regressions between prices and price volatility presented earlier in this report to project daily price volatility over the same time period.

Seasonal Price Volatility

Table 3-4 provides an overview of our gas price forecasts, as well as an assessment of seasonal natural gas price volatility based on EEA's Base Case gas market forecast using the GMDFS. This forecast indicates a continuation of very high (by historical standards) natural gas prices for the foreseeable future.

The projections of seasonal price volatility indicate that seasonal price volatility is also expected to remain relatively high. In the short-term (2003 - 2005), the seasonal price volatility in the producing regions is somewhat lower than we have observed in the past three years. However, the decline is due to the use of normal weather in our forecast, rather than a decline in underlying volatility in the market. In addition, the current high natural gas prices are expected to moderate the normal seasonal swings in natural gas prices over the next two years, as supply responds to the higher prices and working gas in storage returns to more normal levels. As a result, the decline in 2003 - 2005 volatility should not be considered to indicate a moderation of volatility in the market. Another colder than normal winter, similar to the 2002/2003 winter would result in substantially higher volatility than observed during the 2002/2003 winter.

In the longer-term, seasonal volatility is projected to remain at high levels through 2015.

Daily Price Volatility

We have used the regressions between prices and price volatility presented earlier in this report to project the daily price volatility that we expect to see over the 2003 - 2015 time period. EEA's forecast of natural gas prices at the Henry Hub and the associated daily natural gas price volatility is shown in Figure 3-8. Henry Hub prices are expected to remain over $5.00 per Mmbtu in the near-term, declining slightly between 2007 and 2009 when new sources of supply come on line, but increasing steadily thereafter. EEA's forecast indicates that daily natural gas price volatility is expected to remain very high by historical standards. While the projection does not include periods of peak volatility as high as we have observed in the recent past, the overall level of daily price volatility is expected to remain at a high level, falling slightly with natural gas prices through 2007, and then increasing slowly thereafter.

Figure 3-9 shows natural gas prices and price volatility for the New York City area. Volatility in New York City is currently much higher than volatility at Henry Hub due to physical pipeline constraints on delivering natural gas into the New York Metropolitan area. Future volatility in New York City is also expected to increase faster than volatility at the Henry Hub.

Table 3-4
Projections of Seasonal Natural Gas Prices and Volatility

EEA Projected Natural Gas Prices
($/MMBtu)

	Henry Hub	New York City	AECO	Chicago
2003 - 2005	5.79	6.40	5.37	5.86
2005 - 2010	4.74	5.19	4.26	4.81
2011 - 2015	5.95	6.53	4.93	6.05

Projections of Future Natural Gas Price Volatility
(Annualized Return on Monthly Natural Gas Prices)

	Henry Hub	New York City	AECO	Chicago
2003 - 2005	26%	49%	30%	28%
2005 - 2010	41%	50%	42%	42%
2011 - 2015	42%	53%	46%	44%

Figure 3-8

Henry Hub Price and Price Volatility

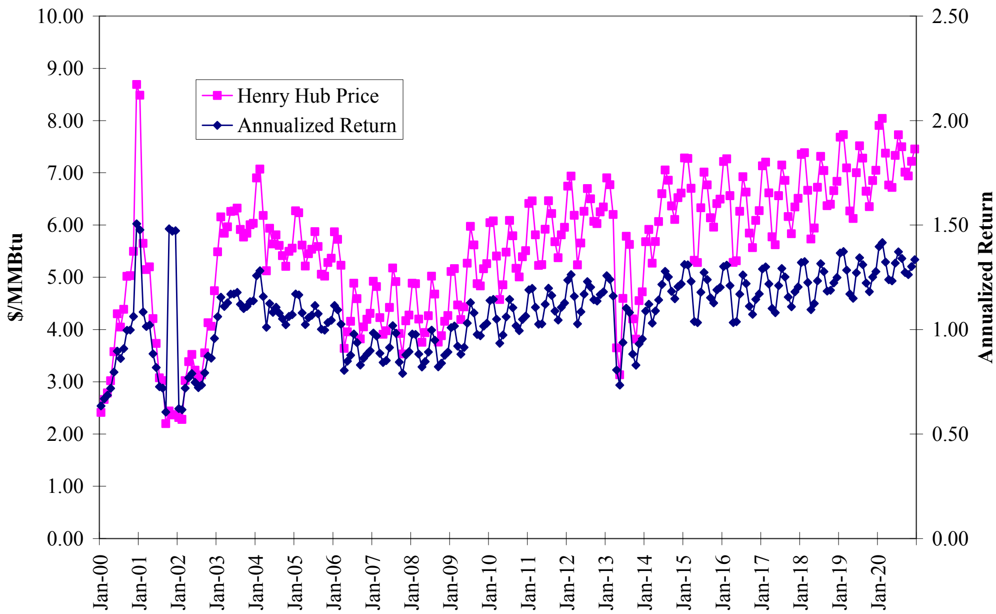
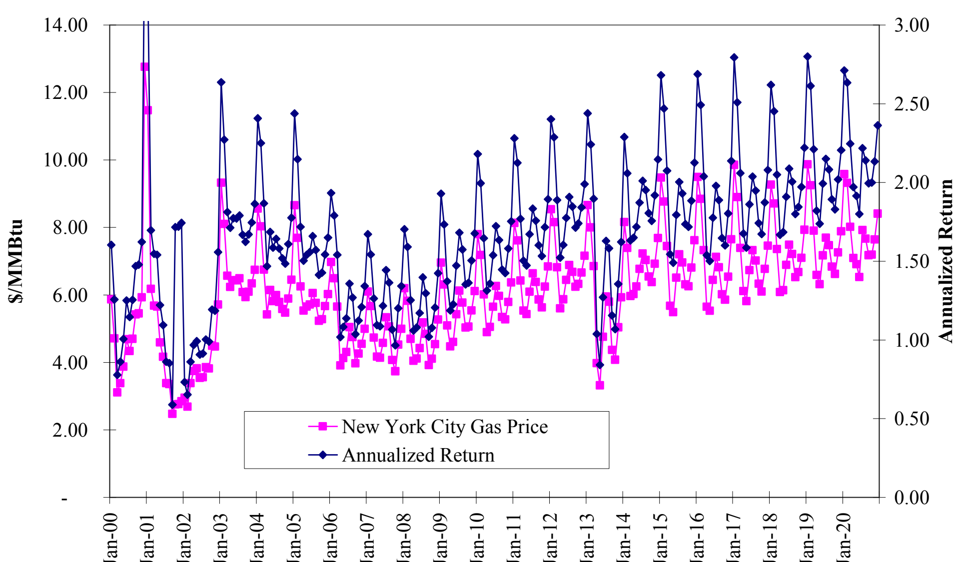


Figure 3-9

New York City Price and Price Volatility



3.5
Potential Impact of Alternative Gas Market Development Scenarios on Future Energy Price Volatility

The projection of future natural gas price volatility presented earlier in this report is based on a continuation of current trends in the commodity-driven gas and electricity markets. However, it is unrealistic to assume that an unabated continuation of the status quo is the only scenario worthy of consideration. Energy markets have been evolving at an extremely rapid pace, and we can be reasonably certain that this evolution will continue. This section highlights several possible scenarios that may evolve in the future. Each scenario focuses on a key driver by creating a series of assumptions regarding market structure, regulation, and participant behavior including investment. We have evaluated the likely impact of each scenario on future gas and electric price volatility, and characterized the likely impacts in terms of a sliding scale that ranges from a more stable price environment to a more volatile price environment. We have also evaluated the likely impact of the scenario on potential market penetration of new natural gas technologies such as distributed generation.

3.5.1 Alternative Market Scenarios

We have evaluated the likely impact on future natural gas prices and price volatility for four different scenarios. Each scenario is summarized below:

Scenario 1: Continued Commoditization (Base Case)

The Base Case scenario reflects a continuation of current trends in the commodity-driven gas and electricity markets. It is characterized by investment in supply and infrastructure that "chases" growth in gas demand for at least the next five years. Energy companies continue to be driven by a need to control costs in an attempt to be profitable. Capital projects, such as major pipeline or frontier energy development projects, are based upon current and near-term market conditions as reflected in the market prices over the last several years. As a result, the North American gas supply/demand balance remains tight. The boom-bust cycle in drilling activity combined with rapid production decline rates prevents extended periods of price moderation on gas markets.

The electricity market is in the "glut" phase of a boom-bust cycle in most regional markets. As a result, electricity prices are determined by the marginal cost of generation with few scarcity rents. The gas price is the key driver of electricity prices, particularly at peak periods. However, new plant construction continues to slow, and cancellations mount. Electricity markets begin to tighten after 2005, with pressure towards increased volatility by 2010.

This scenario is consistent with the current EEA Base Case, and reflects EEA's most likely scenario. There is modest penetration of distributed generation technology, with energy price volatility and the need to control capital expenditures acting to moderate the adoption of the technologies.

Scenario 2 -- Commoditization with Increased Demand-Side Response

The second scenario is a variation of the Base Case Scenario. In this scenario, we are projecting that natural gas and electricity consumers respond to volatility in both natural gas and electricity prices by increasing demand flexibility. Public policy fosters this change by adopting strategies that encourage demand responses.[13] One such strategy is the addition of dual-fuel capacity by large volume customers, including the power generation sector. In addition, in this scenario, the market structure increases the prevalence of real-time price mechanisms for customers that have economic options. For example, more large volume electricity customers are offered power buy-back contracts similar to those currently offered by Georgia Power. These contracts allow large customers to effectively sell purchased electricity back into the market if higher prices make it economic to do so.

The preliminary conclusion is that the scenario can increase the penetration of DG technologies compared to the Base Case. The market evolves with energy service companies (ESCOs) as owners/operators of DG facilities as part of a diversified portfolio of assets, selling delivered energy to ultimate end users. The ESCO manages the facility to arbitrage energy prices, increasing potential and actual demand response.

Scenario 3 -- Expansion of Capacity Contracts Market

This scenario is based upon a market structure for both gas and electricity that features public policies similar to aspects of the "resource adequacy requirements" concept within the FERC Standard Market Design (SMD). The framework fosters longer-term contracts for gas supply, storage, and transportation capacity, creating a form of reserve margin in available energy supply. In some ways, this scenario results in a return to an "Ashbacker" review of infrastructure[14] investments. To accomplish this, the regulatory structure may also need to allow energy asset holders to extract rents (prices above variable cost) from interruptible and large volume customers.

The scenario results in slightly higher long-term average prices, but less volatility. The average prices are slightly higher because capacity utilization of assets is generally lower. Volatility is

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[13] Descriptions of various public policy alternatives that encourage demand response are presented in a Chapter 4, *Strategies for Managing Price Volatility,* of this report.

[14] An Ashbacker review is a regulatory proceeding undertaken by FERC or another regulatory body to ensure that the facilities meet a statutory requirement that they meet the standard of "public interest and necessity." In this review, the regulators evaluate competing proposals to choose the ***individual project*** that the regulators deem to be in the public interest.

lower because the return to longer-term contracts reduces the boom-bust cycle in investment and exploration. However, the price impact differs by customer class. Large volume customers are no longer beneficiaries of intense short-term competition. The adequacy requirements institutionalize reserve margins in all aspects of energy production and delivery.

This scenario generally reduces the risk and increases the economic attractiveness of major new infrastructure investments, including natural gas transportation and storage infrastructure, natural gas power generation, and natural gas distributed generation technologies. The increase in natural gas and electricity prices is expected to make distributed generation technologies more attractive. However this may be offset by a reduction in arbitrage opportunities resulting from the decline in volatility.

Scenario 4 -- Return of Regulation

Calls for rolling back the trend toward deregulated markets in both the natural gas and electricity industries began several years ago. Natural gas and electricity price volatility over the last three years has combined with the ongoing investigations into potential market abuses in California and price index manipulation in California and other markets to reduce confidence in deregulation.

While the pressure to roll back deregulation has not yet resulted in substantial re-regulation, the pressure has effectively halted the movement toward further deregulation in a number of states. In addition, energy companies are trimming back on energy marketing and trading affiliates, and emphasizing growth of their regulated distribution businesses. In Scenario 4, further findings of market abuse by the FERC and by state regulators, combined with public outcry over high prices and energy bills, leads to a certain degree of re-regulation in both electricity and natural gas markets.

3.5.2 Impact of Alternative Scenarios on Price Volatility

As discussed earlier, recent energy prices have been much more volatile than historical trends. With the exception of weather volatility[15], we expect the factors that have created the high degree of volatility to increase in the short-to-medium term under the Base Case scenario (Scenario 1), as natural gas prices remain volatile and the glut of power generation capacity currently existing in many markets disappears. In the longer-term, we expect natural gas markets to become more stable, as new supply resources are developed and the balance between supply and demand shifts from a supply constrained balance to a more normal balance. As the natural gas markets stabilize, the overall volatility of natural gas and electricity prices is expected to remain high by historical standards.

We have used by a qualitative and a quantitative approaches to estimating future natural gas price volatility. Figure 3-10 provides a qualitative assessment of the likely impact on price

[15] Unusual weather patterns have played a significant role in the price volatility in the last three years. With normal weather, we expect volatility to be lower than we have observed over this historical period.

volatility of each of the four scenarios described above. Table 3-5 provides the results of the quantitative analysis of future gas price seasonal volatility for the first three scenarios (status quo, increased demand-side response, and expansion of capacity contracts market) prepared using EEA's GMDFS model.[16]

Figure 3-10
Expected Impact of Alternative Scenarios
on Future Natural Gas Price Volatility

	Stable Prices ------	------	------	------	------	------	------ **Volatile Prices**
1990's Natural Gas Prices	**X**						
Recent Natural Gas Prices[\a]					**X**		
Scenario 1: Base Case - Status Quo							
Near-Term[\b]							**X**
Long-Term[\c]					**X**		
Scenario 2: Increased Demand-Side Response							
Near-Term[\b]						**X**	
Long-Term[\c]				**X**			
Scenario 3: Development of Capacity and Contracts Market							
Near-Term[\b]					**X**		
Long-Term[\c]			**X**				
Scenario 4: Return of Regulation							
Near-Term[\b]		**X**					
Long-Term[\c]					?[\d]		

[a/] Recent Term-includes 2000 - 2002
[b/] Near-term includes 2003 - 2010
[c/] Long-Term includes 2011 - 2015

[d/] Probable return to allocation by regulation and curtailments

16 We have not attempted to develop a quantitative assessment of the impact of the return of regulation scenario.

Table 3-5

Impact Of Alternative Scenarios
On Future Natural Gas Price Volatility
(Annualized Return on Monthly Natural Gas Prices)

Henry Hub

	Status Quo	Increased Demand-Side Response(1)	Development of Capacity and Contracts Markets(2)
2003 - 2005	26%	26%	26%
2005 - 2010	41%	37%	39%
2011 - 2015	42%	38%	38%

New York City

	Status Quo	Increased Demand-Side Response(1)	Development of Capacity and Contracts Markets(2)
2003 - 2005	49%	48%	49%
2005 - 2010	50%	46%	48%
2011 - 2015	53%	48%	49%

(1) Evaluation of impacts to be refined prior to study completion
(2) Evaluation of impacts to be refined prior to study completion

Scenario 2: Increased Demand Response

If future energy markets shift toward Scenario 2 – Increased Demand Response, we would expect to see a noticeable decline in price volatility in both the near-term and the longer-term. The additional capability to switch off of natural gas and electrical system power during higher priced periods will reduce the impact of tight supply and act to stabilize prices. An increase in demand response could be promoted in several different ways.

- Facilitating industrial fuel switching.
- Increasing fuel switching capability in the power generation sector
- Increasing prevalence of real-time natural gas and electricity pricing in the residential and commercial sectors

In order to evaluate the impact of an increased demand response on natural gas prices and volatility, we have developed a scenario with a substantial increase in industrial and power generation fuel switching capability. There are significant logistical and legal hurdles to increasing fuel switching capabilities. Environmental regulations generally limit the amount of fuel switching allowed at a given facility, making the economics of installing fuel switching unattractive to many industrial and power generation facilities. In this scenario, we are assuming that an additional ten percent of total power generation and industrial natural gas demand would be switchable to distillate fuel oil. The increase in fuel flexibility resulting from this gas market shift would result in lower gas demand during the highest price periods, minimizing price spikes during peak periods, and reducing price volatility.

As shown in Table 3-5, this scenario has a noticeable, although not dramatic impact on price volatility. Price volatility at Henry Hub drops by about four percent per year at Henry Hub, and slightly more in major downstream markets. In New York City, expected seasonal price volatility declines by about five percentage points.

Scenario 3: Development of Capacity Contract Markets

The Development of Capacity Contract Market scenario would also be expected to reduce future price volatility. The development of an active long-term contract market for power generation and natural gas transportation and storage capacity will facilitate investment in additional capacity that is expected to reduce the frequency of capacity constraints and limit upward price volatility.

The reduction in capacity constraints on natural gas pipelines and power transmission grids will decrease volatility associated with natural gas and electricity transportation. This is particularly important in markets such as New York City and California where the existence of transportation constraints results in large price movements. Production area prices will also be less volatile due to an increase in the availability of natural gas storage.

In order to evaluate the impact of this scenario, we have assumed that the development of the capacity contract market will increase investment in pipeline and storage capacity by an amount sufficient to reduce the number of days when pipeline basis exceeds the maximum pipeline tariff by 50 percent. Table 3-5 illustrates the potential impacts of this scenario on volatility.

Scenario 4: Return of Regulation

A return to regulation scenario could take a variety of different forms. In our view, many of the regulatory proposals currently being discussed will have only minimal impact on energy prices and price volatility. For example, regulations designed to minimize trading improprieties might be effective in minimizing volatility under extreme circumstances, such as observed in California in 2000. However, if one accepts the premise that market abuses are not widespread, (which EEA believes to be the case) these regulations are unlikely to significantly impact the general level of volatility in the market.

Regulations that impose an actual or defacto price cap are likely to have a significant impact on prices and volatility. In the short term, price caps would substantially reduce price volatility, and would have the potential to reduce average prices.

In the longer term, price volatility in a price cap scenario is harder to foresee. To the extent that the increased regulation is effective, prices should remain more stable than the status quo scenario. However, the imposition of price caps or other regulatory constraints on prices will result in an allocation of resources based on regulatory structures rather than by market forces. We believe that this will create intense pressure to find ways of marketing energy supplies outside of the regulatory structure. If these "gray markets" do develop, the volatility in the overall market will be concentrated on this single element of the market, resulting in an increase in potential price volatility.

In addition, one of the major impacts of an effective price cap is a reduction in the economic incentives to invest in new production and transportation infrastructure, resulting in potential supply shortages, and a return to regulatory curtailment.

Imposition of a binding price cap in the electricity markets would substantially reduce the economic incentive to install new gas-fired power generation. A significant portion of the economic value of these facilities occurs during periods with the highest prices. Capped prices would reduce profitability during those periods, reducing overall facility profitability. A rebound in regulatory oversight of power sales would also tend to increase the difficulty of selling power into the grid.

In some markets, price caps might also increase incentives to install distributed generation and CHP technologies. Price caps are likely to result in electricity supply shortages in certain markets and for certain periods, and to increase the likelihood of supply interruptions. Regulators respond to rolling blackouts, similar to those observed in California, with regulatory allocation of supply, including curtailment of supply in some markets and/or increases in voluntary load shedding programs. Both the possibility of involuntary curtailment and the increased use of voluntary load shedding programs would provide an incentive to install backup generation capabilities, including distributed generation capacity.

Overall, actions to stabilize gas prices through direct regulatory means will decrease the market's ability to allocate natural gas resources efficiently, with the likely impact of reducing natural gas supply available to large incremental users during peak periods.

3.5.3 Impact of Alternative Scenarios on Penetration of Gas Technologies

The different energy market scenarios discussed above will have potentially different impacts on the market penetration of natural gas distributed generation (DG) and combined heat and power (CHP) technologies.

Chapter Five evaluates the impact of price volatility on the market penetration of DG and CHP technologies for different customer groups. As discussed in more detail in chapter Five, our discussions with customers, ESCOs, utilities and manufacturers, along with our review and analysis of third-party customer research, suggest that different customer groups will respond to price volatility in different manners, hence are likely to respond differently to the alternative future gas market scenarios. Below, we summarize our general conclusions about price volatility impacts on DG/CHP investment decisions for each major customer class.

- <u>Price volatility is likely to have little impact on smaller commercial customers.</u> Smaller customers, those without access to open energy markets or to non-utility suppliers, and those less familiar with energy technologies and markets, tend not to separate short-term volatility from changes in overall price levels. Many have not yet considered DG/CHP. Price volatility, if considered at all, would be reflected in their expectations about overall price levels in the future. The up-front costs of the equipment, the need for expertise in operation and maintenance, and internal decision-making processes and criteria are likely to discourage investment in DG/CHP without price volatility having ever entered the picture. Hence, changes in price volatility scenarios are unlikely to impact the penetration of DG and CHP technologies in this market segment.

- <u>Price volatility may slow DG/CHP decisions by commercial and small industrial customers.</u> National account customers and others with more sophistication about energy may understand volatility in the energy markets. They may be purchasing natural gas and/or electricity on the open market or from marketers for a number of locations around the country. Thus, they are managing price risks on the commodity side, through marketers or independent hedging, rather than through investment in certain types of energy equipment.

  Interest in DG in this segment is driven mainly by opportunity cost of outages and quality disturbances and by high electricity prices (especially demand charges) relative to natural gas. Internal criteria can preclude DG ownership, especially very short required payback periods and competing, more visible uses for capital. As these customers consider DG/CHP, their desire for more stable prices may be expressed through use of an ESCO to install, own and operate DG/CHP for them. For some, however, expectations about instability are leading to postponement of DG/CHP implementation. Hence, scenarios with lower price volatility are likely to promote increased penetration of DG and CHP technologies in this market.

- <u>For industrial customers, price volatility may encourage DG/CHP, depending on other factors.</u> With significant thermal loads, dual- and alternate-fuel capabilities, and a history of CHP use, CHP is often considered attractive without thought for price volatility. Many customers in this segment have already installed CHP. With the most experience, sophistication and market/technology savvy, these larger industrial customers are much more likely than other sectors to view DG as a physical hedge against volatile electricity prices. They consider it to be one of an array of tools that can work together to minimize energy costs.

- <u>Residential customers: no impact expected.</u> While residential DG/CHP products are not yet on the market, research suggests that price volatility is neither a motivator nor a deterrent in consideration of DG, even in areas where price spike events have occurred. Consumers tend to view DG as virtually an exact substitute for grid power, i.e., as just another way to fulfill the basic need for electricity in the home. This research suggests that the different scenarios in the electricity and natural gas markets will not result in significant changes in residential homeowner decisions about future DG product offerings.

- Energy price volatility is likely to encourage DG/CHP investment by ESCOs.
  ESCOs perceive profitable opportunities to provide price stability to industrial and commercial customers by generating electricity and thermal energy with DG/CHP and selling it to them at a price that guarantees savings over their current bills. The presence of volatility appears to be a factor that causes end-use customers to become interested in ESCO services. A few ESCOs also see opportunities for further benefiting customers through installation of thermally activated technologies – absorption cooling and desiccant dehumidification – that help reduce peak electric demand by reducing electric cooling loads.

Figure 3-11 provides a qualitative assessment of the probable impact of each of the different scenarios on the market penetration of DG and CHP technologies. The scale in this figure is relative to the expected market penetration of these technologies in the near-term in Scenario 1 (Base Case).

In Scenario 1, we expect future market penetration of DG and CHP technologies to be greater than current market penetration due to improvements in technology that result in lower costs. The market invests in modest improvements in the physical infrastructure needed to connect DG and CHP systems to the power grid, resulting in wider customer acceptance of the technologies.

Overall, we expect to see an increase in the penetration of CHP and DG technologies as part of Scenario 2. In fact, increased penetration of CHP and DG technologies would be expected to be an integral component in the development of the scenario. DG would be expected to be a key component in the moderation of electricity price volatility foreseen under this scenario. In addition, growth in dual-fuel fired CHP will result in additional fuel switching capability between gas and alternative fuels, which is required as part of this scenario. As a result, we would expect to see increased penetration of both DG and CHP under this scenario.

In Scenario 3, the development of an effective capacity and contracts market is likely to reduce the incentives to install distributed generation and other distributed natural gas technologies for the larger and more sophisticated customers. The increase in power generation capacity associated with the capacity and contracts market will result in more stable power prices and more reliable services than in the Base Case. Both price stability and reliability reduce the incentive to invest in CHP and DG by the larger and more sophisticated commercial, industrial, and ESCO customers, while potentially increasing investment in these technologies by smaller customers who see cost savings associated with the technologies before consideration of price volatility.

The return of regulation in Scenario 4 is also expected to reduce the attractiveness of the distributed generation market for most customers. Increased regulation is likely to reduce the ability of potential DG and CHP customers to profitably market excess power. In addition, increased regulation of natural gas markets that result in allocation of natural gas resources by regulation rather than price may result in a decrease in fuel reliability of gas-fired DG and CHP.

Figure 3-11
Expected Impact of Alternative Scenarios
on Future Natural Gas Technology Penetration

	Lower Penetration ----	----	----	----	----	---- **Higher Penetration**
Scenario 1: Status Quo						
Near-Term[\a]			**X**			
Long-Term[\b]					**X**	
Scenario 2: Increased Demand-Side Response						
Near-Term[\a]					**X**	
Long-Term[\b]						**X**
Scenario 3: Development of Capacity and Contracts Market						
Near-Term[\a]		**X**				
Long-Term[\b]				**X**		
Scenario 4: Return of Regulation						
Near-Term[\a]	**X**					
Long-Term[\b]	**X**					

[a/]Near-Term includes 2003 - 2010
[b/]Long-Term includes 2011 - 2020

3.6
Conclusions

Over the past two decades, the structure and regulation of the natural gas industry has been changed in a manner that, where ever possible, attempted to harness "market force" to improve economic efficiency and to assure that energy prices are maintained as low as possible consistent with reliability and other public policy objectives. Wellhead price decontrol, unbundling, and customer choice programs are examples of methods by which the restructuring was implemented. More recently, regulatory and legislative proposals have attempted to apply a similar "market" discipline to the electricity industry.

Competitive markets provide a tremendous incentive for service providers to seek to reduce costs to the greatest extent possible. As one method of reducing costs, LDCs and retail energy marketers have sought to increase the utilization of all assets, such as pipeline capacity contracts, thereby reducing "per unit" costs. Similarly, competition has driven gas producers to increase the rate that reserves are produced (i.e., increasing decline rates).

In the competitive market, energy companies recover their capital investment only when there is scarcity. When there is "slack" capacity, prices are driven towards variable costs. New capital investment occurs only when the price signals indicate that the investment is required. As a result, there is less "slack" capacity available to satisfy unexpected increases in gas requirements. While "economically efficient," this investment pattern creates an extremely delicate balance in the natural gas market. ***The increases in gas price volatility that have been observed over the past five years results in large part from the reduction in "slack" capacity driven by a competitive market structure combined with the relatively large swings in demand that can be caused by weather patterns. Barring structural changes, natural gas markets will be at least as volatile or more volatile in the future.*** A number of factors contribute to this basic conclusion.

On the supply side, the gas market will increasingly rely on frontier gas resources to meet demand. These projects are clearly needed and will result in the availability of more gas supply and lower average price than would occur in the absence of these projects. However, these frontier supplies will not reduce volatility. Rather, reliance on these resources tends to increase natural gas volatility relative to other more conventional supply sources due to several of the characteristics of frontier supplies.

Frontier projects tend to require huge up-front investments, but have very low incremental costs after the initial investment is completed. As a result, there is a stronger than normal incentive to maintain maximum production levels from frontier projects, and the price at which a production shut-in would occur is typically lower than for conventional resources. This tends to decrease short-term supply response to price. Most frontier projects can be expected to flow at as close to capacity as is operationally possible, regardless of market conditions.

On the demand side, daily demand volatility will continue to increase over time. The growth in weather sensitive load will increase demand response to changes in weather, increasing overall demand volatility. The large increase in gas-fired power generation capacity with rapid and less predictable swings in gas requirements will increase fluctuations in natural gas demand. 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 load to switch to oil during periods of tightness in the gas market will increase gas market volatility. These limitations reduce the responsiveness of gas demand to increases in prices.

Additionally, in the short-term, capital constraints will continue to inhibit the flow of investment into natural gas and electricity infrastructure to at least some degree. These capital constraints will limit the investment in infrastructure needed to increase the supply capability available to moderate volatility.

Finally, it will be difficult to achieve consensus to adopt policies that create an incentive or requirement to invest in infrastructure that create supply capacity needed to moderate volatility without a significant popular support. Moreover, the general population does not understand the fundamental causes of energy price volatility and is more likely to attribute price movements to market manipulation and profiteering. As a result, there is a significant risk that any public outcry for policies designed to address volatility would not result in the needed investment in infrastructure.