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.

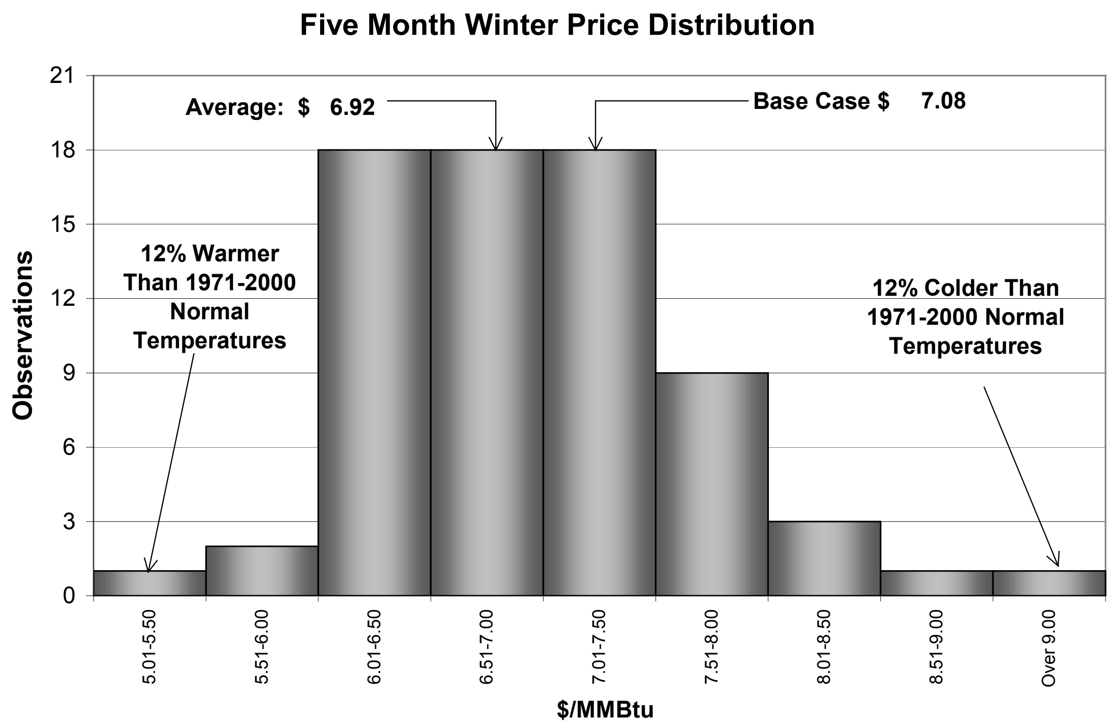
Day-to-day, month-to-month, and year-to-year weather patterns tend to be normally distributed around very long-term trends. However, price response to changes in demand due to changes in weather is not normally distributed. As illustrated in these charts, the impact of weather on prices tends to be asymmetrical, 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



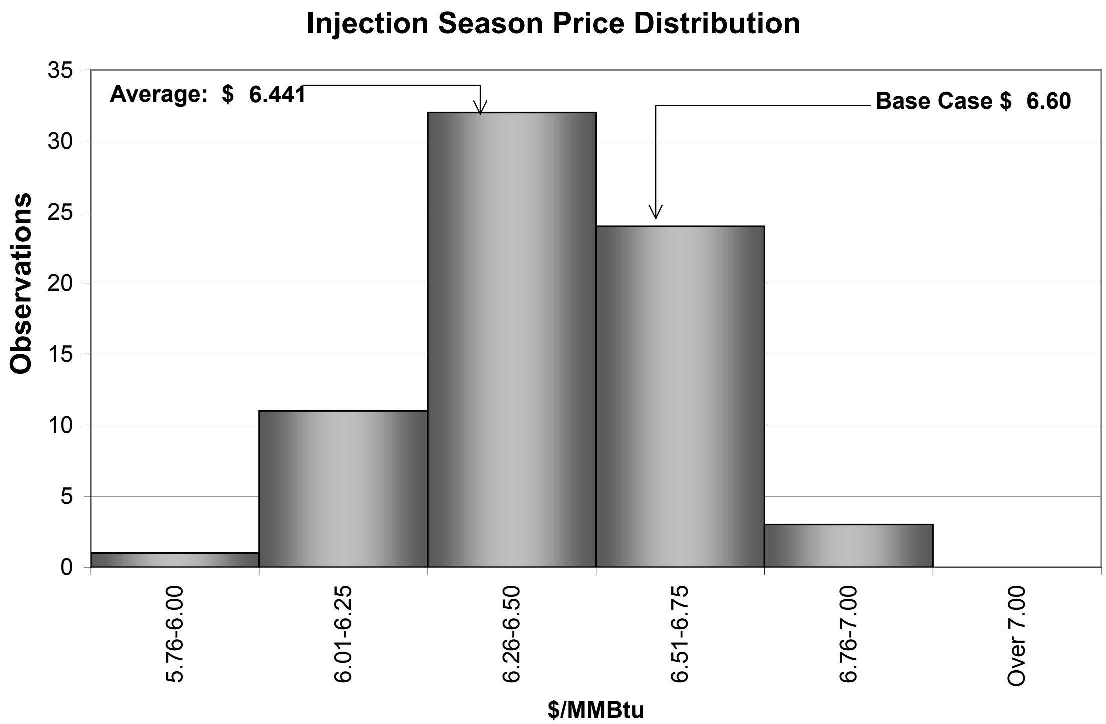
2) Fuel Switching

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., Fuel Switching Issues in the Industrial Sector, 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.

[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

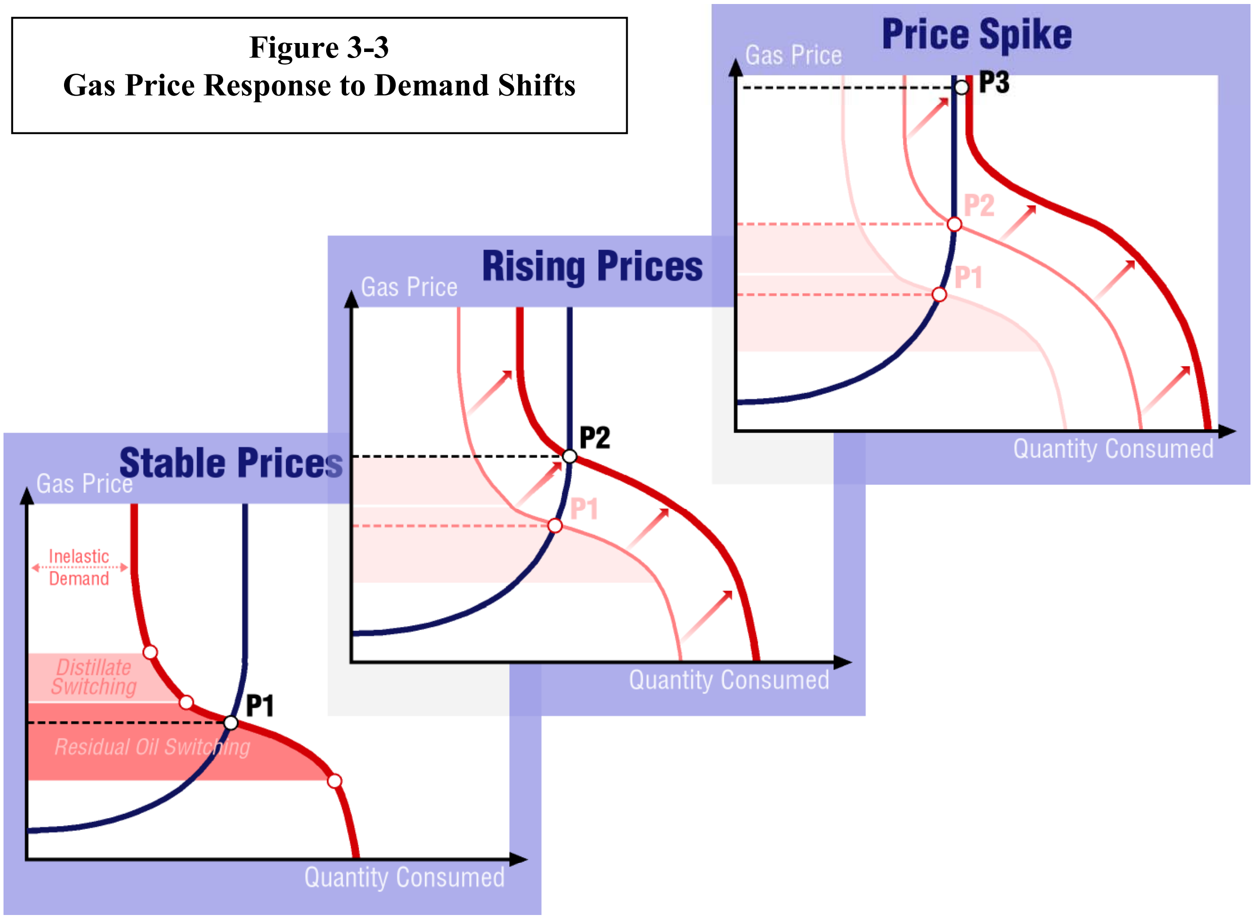
EEA has evaluated the fundamental drivers of daily price volatility in order to project future trends in natural gas price volatility. Conceptually, daily price volatility is a function of daily demand volatility, combined with supply constraints. In a tight market, changes in daily demand are expected 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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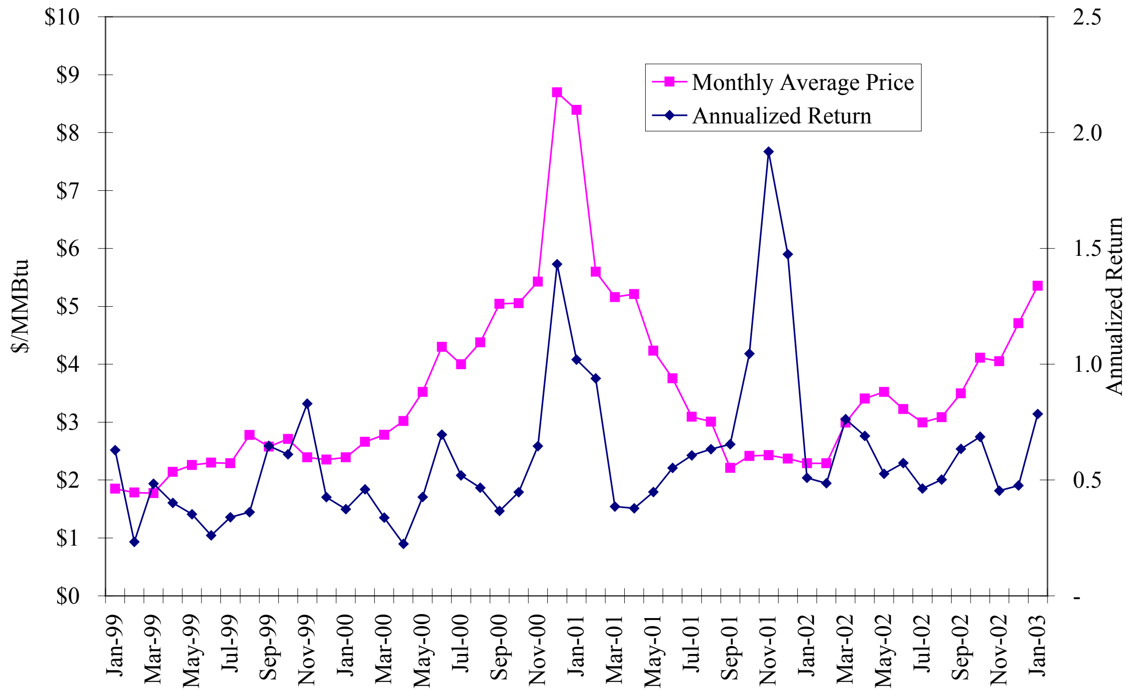
[7] Annualized return is a relative measure of volatility, hence is not dependent on the actual level of prices.

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.

[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.

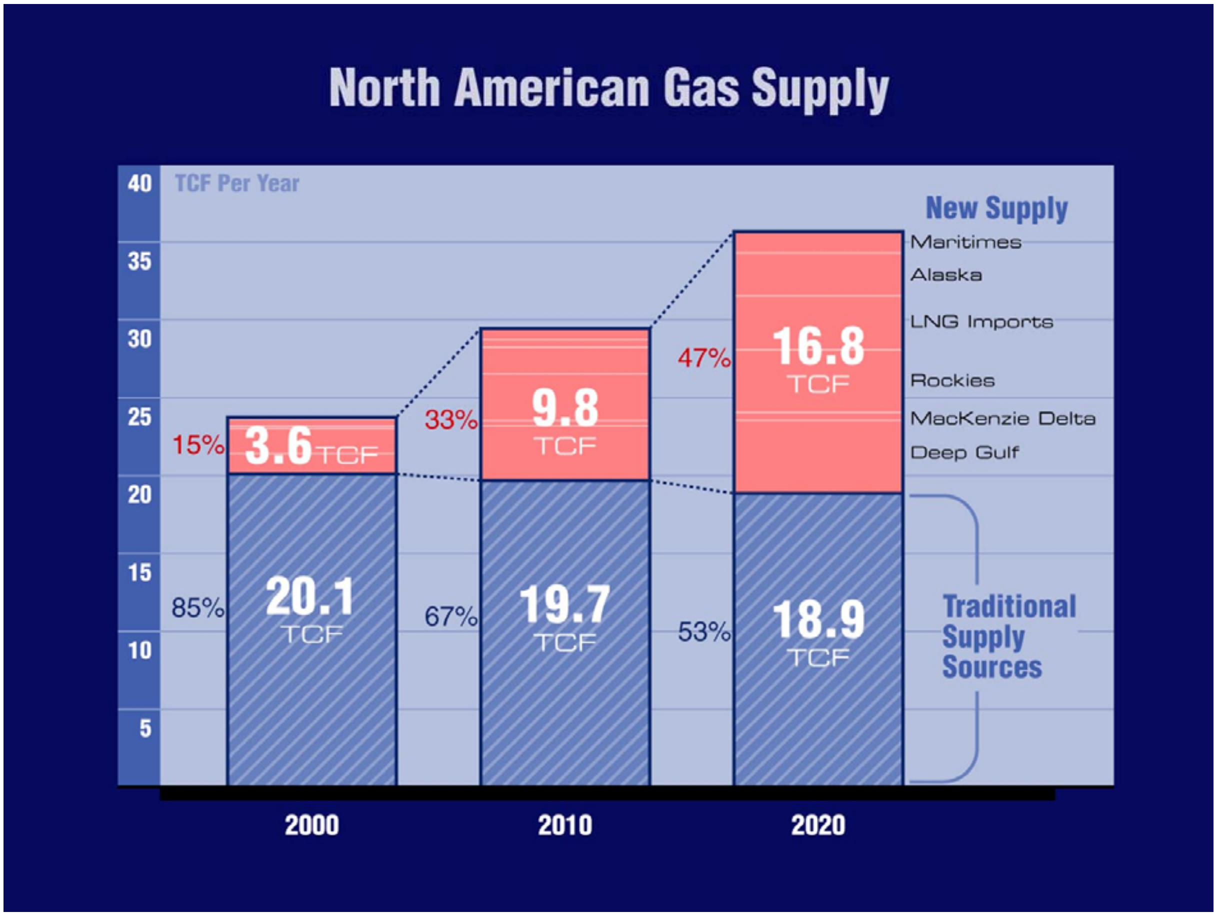
The large price movements that will be needed to balance supply and demand in this case can be minimized if sufficient storage capacity is available to absorb the excess production.

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.

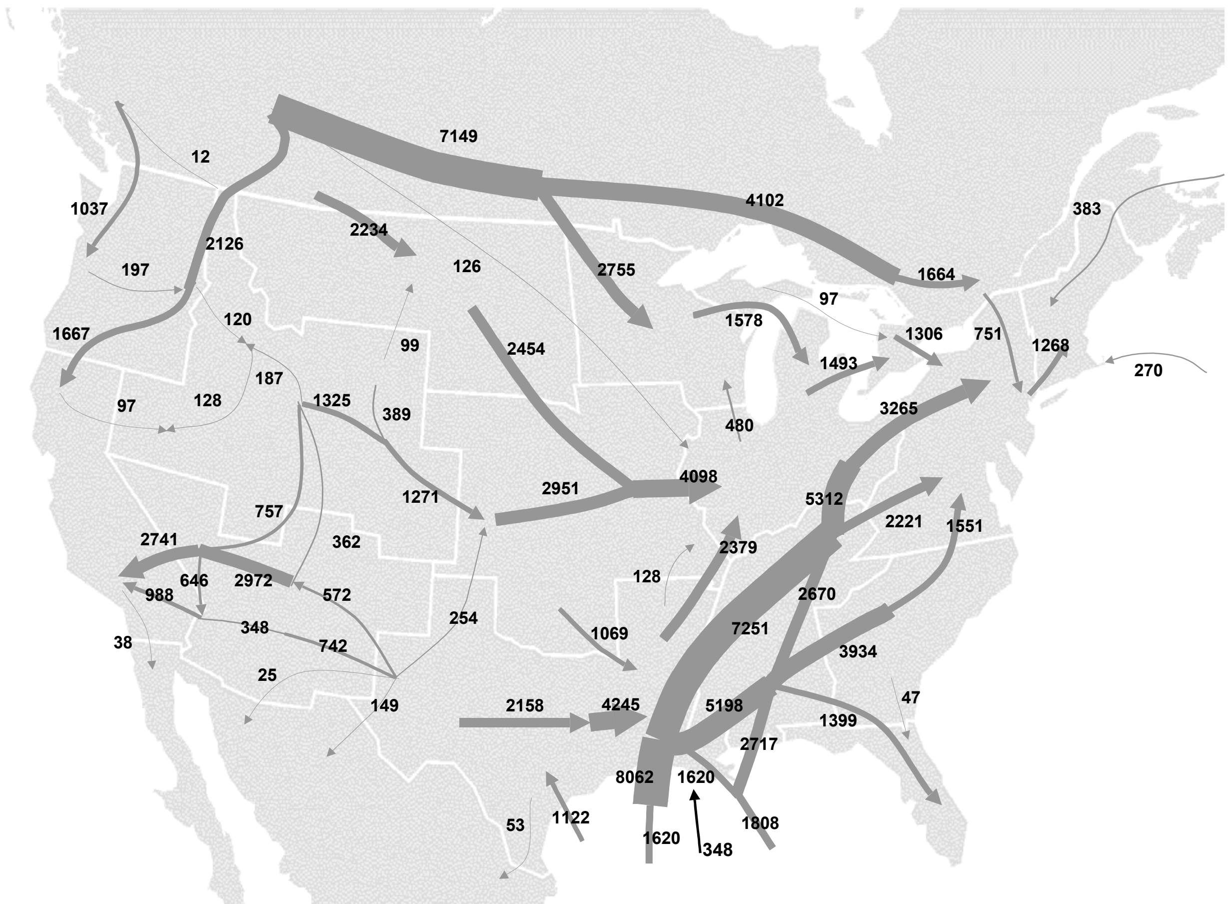
Pipeline Transportation Requirements

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.

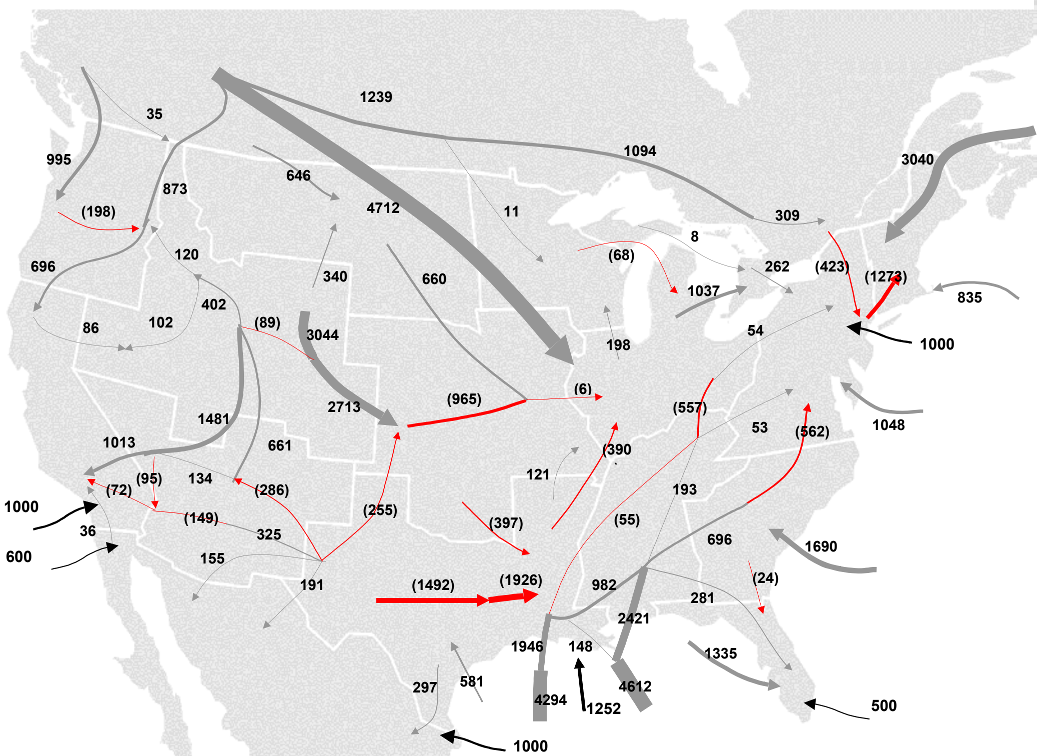
Along with major projects connecting new supply basins, there will be numerous pipeline projects to relieve local bottlenecks in market areas.

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

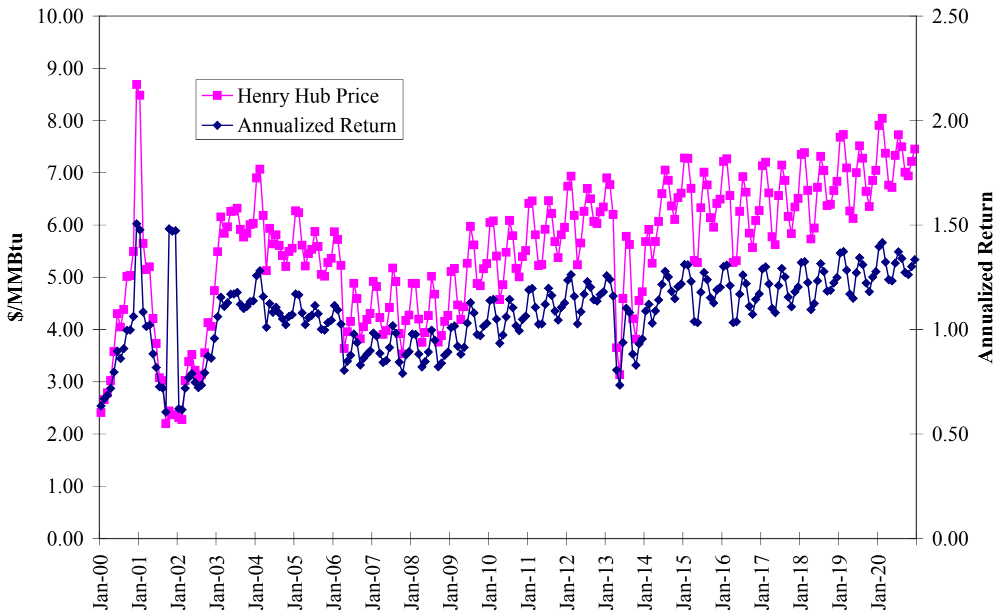
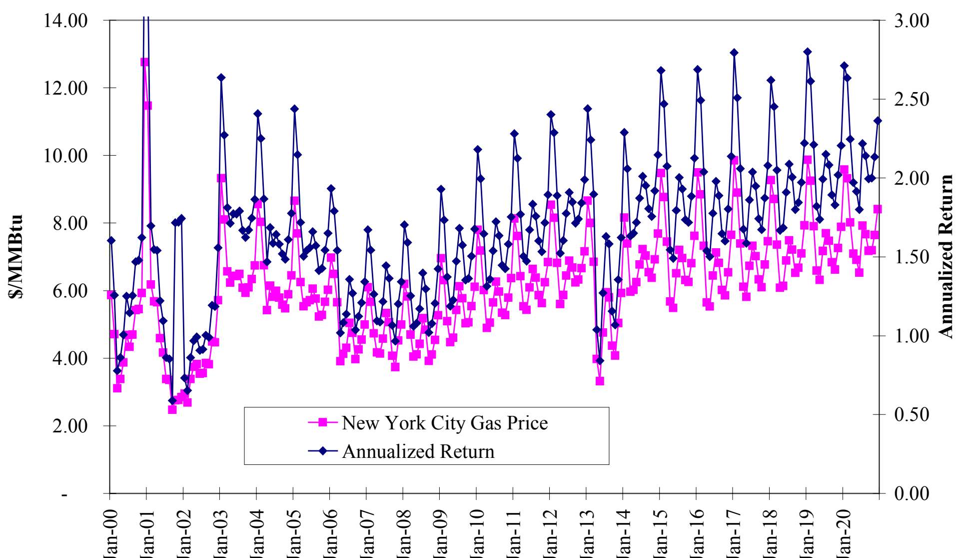


Figure 3-9

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.

- Price volatility is likely to have little impact on smaller commercial customers. 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.

- Price volatility may slow DG/CHP decisions by commercial and small industrial customers. 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.

- For industrial customers, price volatility may encourage DG/CHP, depending on other factors. 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.

- Residential customers: no impact expected. 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.

4 Strategies for Managing Price Volatility

4.1 Background

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

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

As discussed in Chapter One of this report the impacts of energy price volatility fall into one of two categories:

1) Investment/planning price volatility. Planning price volatility refers to long-term uncertainty in energy price levels that influence investment planning.

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

The focus of this report is the development of strategies principally designed to address investment/planning volatility in natural gas prices. In most instances, it is the unanticipated changes from one winter to the next or over the next few years that create the negative consequences for market development for distributed generation and present the greatest risk to gas consumers and market participants.

The impact of trading price volatility is generally limited to those entities that trade large dollar value positions in the short-term market. Trading losses were an important factor in the recent decline in the financial health of many large energy companies and therefore create critical challenges for the natural gas industry. However, the strategies used to address trading volatility are less applicable to most market participants and will not be addressed in great detail.

The objective of this chapter of the report is to consider strategies, policies, and approaches that can be used to reduce the destructive effects of price volatility. The chapter is divided in two sections. Section 2 presents a discussion of basic techniques that service providers or consumers can use to manage price volatility. The section also presents a discussion of the elements of risk associated with price volatility and the interdependencies of these elements. The section concludes with a discussion of some generic barriers to implementing the techniques with a focus on the relationships between utility regulation and price volatility management.

Section 3 presents 15 specific strategies for addressing price volatility. The strategies considered fall into two broad categories.

1) Volatility Management Strategies: Strategies, policies, and approaches that can be used to manage price volatility. These techniques are designed to reduce the negative impacts in a volatile energy price environment. In general, these are strategies that can be adopted by an individual market participant. The strategies are differentiated as consumer-initiated strategies and vendor-initiated strategies.

2) Volatility Reduction Strategies: Strategies, policies, and approaches that may reduce energy price volatility. These approaches could potentially reduce price volatility by increasing the elasticity of supply and/or demand (i.e., increase the magnitude of the market response to changes in energy prices) in the broader market. In general, these strategies would require a fundamental change in the structure of the market and would need to be adopted broadly by market participants to be effective.

The format for the exposition is as follows. A description of the strategy is presented along with a statement of the specific objective of the strategy. The “Pros” and “Cons” of each strategy are identified. Finally, barriers to implementing the strategy are discussed.

The strategies developed here address natural gas price volatility, with an emphasis on their applicability to the emerging distributed generation market. Nevertheless, in a number of instances, the strategy can be readily adapted to addressing volatility in other energy markets, such as electricity or oil. One must recognize, however, that regulation – particularly utility regulation – can significantly complicate the implementation of some of the strategies. These issues will be explicitly discussed.

4.2
Managing Price Volatility: Techniques, Issues and Barriers

Strategies designed to ***manage*** price volatility all involve allocating price risk among the market participants. The strategies do not change the underlying volatility of natural gas prices. These strategies represent alternatives that may be used in a market environment with highly volatile prices.

In a real sense, the re-allocation of risk embodied in these strategies are fundamentally a "zero sum" game. These strategies do relatively little to affect the underlying price volatility in the market. To the extent that the price risk for one participant is reduced, the price risk for another participant is increased. In considering these strategies, a market participant should carefully assess the nature of the risk and quantify the magnitude of any risk that is assumed.

For a regulated entity such as a natural gas local distribution company (LDC), it is important to fully integrate any strategy into the framework of regulatory review and oversight used by the regulators. Many of the elements of the strategies presented will require regulatory approval and in some instances, regulators have been reluctant to grant approval of the type of program suggested by the strategy. As a result, regulatory approval of some elements of the strategies may be difficult to obtain and will require intensive education of regulators regarding the relationship between price volatility management and the element of the strategy. Moreover, certain regulatory models (e.g., performance-based rates or rate cap regulation) may present additional challenges to the adoption of individual strategies.

Four basic elements are common to a number of the management strategies.[1] They are:

- Market segmentation – Market segmentation refers to the differentiation of customers based upon the characteristics of the customer. In the context of strategies to manage price volatility, segmentation involves differentiating the customers based upon their risk tolerance and need for price stability.

- Long-term (multi-year) contracts – The effect of a long-term contract is to transfer an entitlement and/or obligation between two or more parties. Contracts are the basic business tool for the allocation of risk between parties.

1 Specific strategies are presented in Section 3.

- Asset diversification – The value of energy production or delivery assets is highly correlated to the market price of energy. As a result, a diversified portfolio of energy production or delivery assets can be used to balance energy price risk. When the energy production assets span energy commodities with prices that are uncorrelated or loosely correlated, the portfolio provides additional insulation from price volatility and may provide arbitrage opportunities.

- Financial derivatives – Financial derivatives (e.g., futures, options, and swaps) are a contractual vehicle that conveys a right and/or obligation to buy or sell a commodity (such as natural gas) at a specified price. Financial derivatives can offer a method of offsetting price risk with modest transaction costs.

4.2.1 Managing Natural Gas Price Risk

Three of the four basic elements presented above – long-term contracts, asset acquisition, and financial derivatives – form the core tools for a commodity price hedging strategy. Hedging can be simply defined as establishing a price today for some good or service that will be bought or sold at some time in the future. By "fixing" the price for some future transaction, the value of the transaction to the market participant will not change with price movements in the market.

4.2.1.1 Hedging a Gas Acquisition Portfolio

Prior to the restructuring of the gas industry that began in the late 1970s, the principle objective of a supply portfolio was to assure the reliability of supply. However, with unbundling[2], a principal objective of gas supply portfolio management became gas cost minimization. In the wake of the 2000–01 gas price run up, gas price stabilization has become an additional objective of supply portfolio management.

Price stabilization is realized through a program of hedging of gas supply costs. The objective of a hedging program is to provide price stability and predictability. This is achieved by locking in future prices with a combination of physical and financial tools. LDCs hedged gas supplies with three basis tools:

- Seasonal storage injections and withdrawals of gas supplies;

- Long-term[3] firm transportation contracts with pipelines;

- Multi-month fixed price gas supply contract;

- Financial hedges.

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[2] A description of gas industry restructuring and unbundling, as well as the implications for gas price volatility, is contained in the companion report, *Price Volatility in Today's Energy Markets.*

[3] FERC defined long-term firm transportation contracts as contracts that are one-year or longer.

The first three of these tools involve physical hedges. They are extremely well understood in the gas industry and have been utilized in gas supply portfolio management for decades.

All of the LDCs interviewed hedged at least some of their gas supply for system customers with a mix of physical hedging tools. However, a number of the activities that provide some degree of a price hedge are viewed by LDCs principally as a method of obtaining reliable gas supplies or gas cost minimization. The price stabilization impacts of the activity were recognized by the LDC, but were often considered a secondary benefit.

Gas Storage

All of the LDCs interviewed purchased gas during off-peak periods and injected gas into storage. Storage gas provides a natural hedge against unanticipated changes in price. However, most LDCs view the primary purpose of storage as a method of insuring reliability and as a method of managing pipeline demand charges associated with firm transportation contracts. Two-thirds of the companies questioned identified storage as a hedging tool without prompting. In further discussions, all of the LDCs recognized the price stabilization effects of storage gas.

Placing gas into storage is not risk free. Because of weather patterns and other market conditions, the price of gas in the winter withdrawal season has been below the injection season price in two of the last five years. As a result, use of storage gas does not always minimize gas costs. However, storage gas always serves to stabilize price movements by diversifying the timing of gas purchases.

Long-term Firm Transportation Pipeline Contracts

All LDCs interviewed also used long-term firm transportation contracts. However, once again, the LDCs did not identify hedging as the reason for the contractual commitment. Reliability was identified as the principal rationale for entering into firm transportation (FT) contracts. Nevertheless, an FT contract provides a hedge against "basis blowout" – a sudden increase in the market value of gas transportation that can occur in pipeline constrained markets.

However, FT contracts are an expensive method of hedging against basis blowout. Over the past five years, the average transportation basis has remained well below the maximum regulated rate for transportation contract. In many markets in the Midwest, basis values averaged less than 40 percent of the maximum regulated rate for firm transportation contract. Even in pipeline constrained markets such as New York, Florida, and California, the annual basis value rarely exceeds the maximum transportation rate to a significant extent.[4] As a result, the cost of a maximum rate contract is far above the expected basis value, implying a significant spread between the contract and the market rate.

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[4] Generally, when annual basis exceed maximum transportation rates, pipelines are able to market capacity expansions. The expansions have the effect of reducing the annual basis after the expansion is completed.

Multi-month Gas Supply Contracts

All of the LDCs interviewed use multi-month gas supply contracts as part of their gas supply portfolio. In the 2000-01 winter, more than 80 percent of LDCs surveyed indicated that their gas supply portfolio included long-term contracts, defined as one year or longer. However, the vast majority of these contracts – 75 percent – used "first of the month" index pricing rather than fixed prices. As such, these long-term contracts did not serve as a price hedge.[5]

About 53 percent of companies use some fixed price contract to hedge gas prices. The amount of gas supply hedged varied significantly from company to company, from less than 10 percent to more than 30 percent of the expected winter purchases. There is no uniform practice in the industry.

Hedging with Financial Tools

Financial hedges include a seemingly endless array of contract vehicles. Financial derivatives (e.g., futures, options, and swaps) are a contractual vehicle that conveys a right and/or obligation to buy or sell a commodity (such as natural gas) at a specified price. The contracts convey a right and/or obligation to buy or sell a natural gas at some time in the future for a specified price and under specified terms and conditions. A discussion of the use of financial hedges to mitigate price risk is presented in Appendix F.

The use of financial hedges as a gas price management tool has grown dramatically. Prior to 1995, very few LDCs used financial instruments. By the 2001-2002 winter heating season, 55 percent of LDCs surveyed used financial instruments. The transaction cost of financial hedging tools can often be less than physical hedges, contributing to their appeal. However, as discussed later, the tools can present elements of regulatory risk to LDCs.

Weather Derivatives

Weather derivatives are products that were developed specially for the management of weather related price and volume risk in energy market. For years, financial houses offered weather insurance to farmers and other producers of products that could be affected by weather. The providers of these contracts recognized that there was an opportunity to develop products for energy companies.

The weather risk management product class includes caps, floors, collars, and swaps with payouts defined as a specified dollar sum multiplied by differences between the Heating Degree Day (HDD) level specified in the contract (i.e. the "Strike") and the actual HDD level which occurred during the contract period.

There are no standardized swap transactions. However, most transactions involve an exchange of periodic payments between two parties, with one side paying a fixed price and the other side

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5 *LDC Supply Portfolio Management During the 2001-2002 Winter Heating Season*, July 2002, American Gas Association.

paying a variable price. Specific terms of swap agreements - including the fixed price of a commodity and its floating price reference, the term of the contract, and the quantity to be hedged - are established by the two parties involved, and can vary, subject to their specific needs and objectives.

A recent survey compiled by Weather Risk Management Association (WRMA) and PriceWaterhouseCoopers shows that the number of weather transactions grew 43 percent from April 1, 2001, to March 31, 2002, with 3,937 transactions that had a total value of $4.3 billion, which is a 72 percent increase over the year before. Despite this growth in transactions, only 13 percent of LDCs surveyed reported using weather derivatives during the 2001-2002 heating season.

4.2.1.2 Hedging Fundamentals: Costs and Risks

Hedging is not a risk-free activity. While hedging can result in lower gas prices if the market prices are higher than expected, it can also result in costs higher than the market if, for example, the market falls due to factors such as a warmer than normal winter. In any given period, there is a roughly equal chance that the cost of a hedged gas portfolio will be above the market price as there is that the cost of the hedged portfolio will be below the market price.

To understand this more fully, consider the following hypothetical hedging program. Assume that a gas "buyer" requires 24,000,000 cubic feet per month. In order to manage gas price volatility risk, this shipper could build up a series of purchase contracts that "ladder" the expiration dates so that one contract expires every month. Although the example uses long-term gas purchase contracts, an equivalent hedging program could be created using financial hedging products.

Figure 4-1

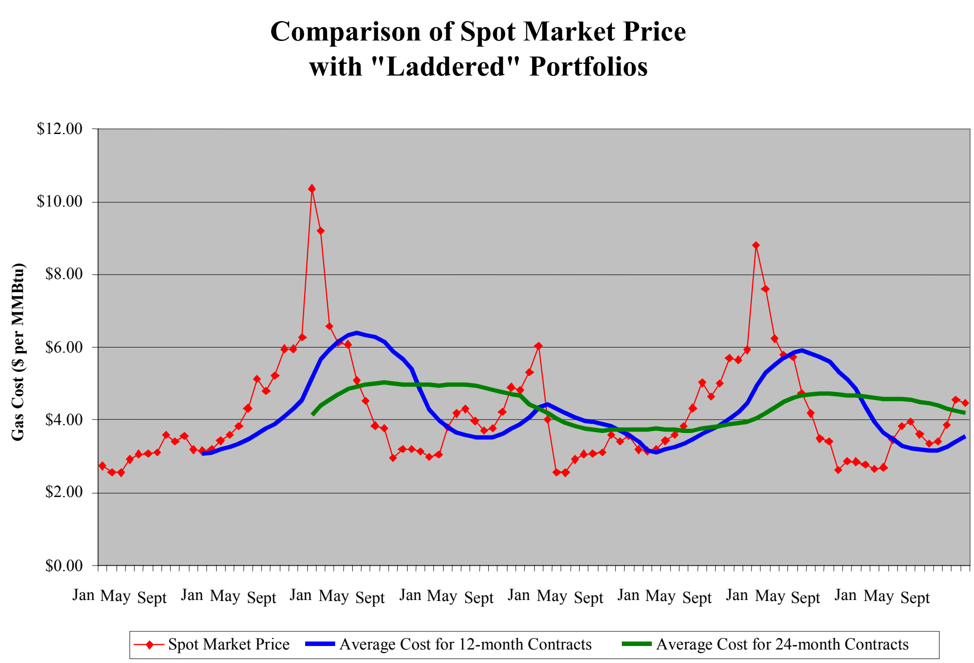


Figure 4-1 presents a comparison of spot market gas prices to the average gas prices for two contract portfolios. In one case, the gas "buyer" chooses to maintain a portfolio of 12-month contracts. In the second case, the portfolio consists of 24-month contracts.

The figure presents hypothetical price data for an 8-year period constructed from gas prices and price volatility in Chicago from 1999 though 2003. The illustration also assumes that there is no premium or discount in the average price of a multi-month contract. The average price over the entire period is essentially the same for the three approaches. However, at any given point in time, the price for gas purchased with a hedged portfolio can be above or below the "market" price.

Both of the portfolios of longer-term contracts reduce volatility compared to the spot market with the portfolio of 24-month contracts providing even greater price stability than the portfolio of 12-month contracts. By increasing the length of the contract, the portfolio provides the additional price stability that is expected.

Credit Risk

But the longer-term contracts also add a liability to the buyer's balance sheet. The magnitude of the liability is directly proportional to weighted-average of term of the contacts in the portfolio. In other words, the liability of a five-year fixed price contract is five times greater than the liability of one-year contract for the same daily volume. So long as the "buyer" is large and financially healthy, the liability may not be a problem. If the dollar value of the gas purchase commitment is large compared to the size of the "buyer", the obligation can create "credit risk" that increases the costs of financing and creates pressure on the equity prices of any company in such a position. In the wake of the Enron bankruptcy, problems created by "credit risk" have decimated many of the largest energy marketing firms.

Volume Risk

Extending the term of the contracts in a gas portfolio can also create "volume risk." The example presented above assumes that the gas "buyer" knows that the gas requirement will be 24,000,000 cubic feet per month. However, any forecast of gas requirements becomes less accurate as the projection goes further and further into the future. So long as the actual gas requirements are above the forecasted gas requirement, the problem is limited to a need to acquire additional gas at "market" prices. If the market price is above the average cost of the portfolio, the effect is to increase the average cost of gas slightly.

However, if the actual requirements are below the forecasted requirement, the "buyer" is in the position of having committed to buy more gas than is needed and will need to sell gas back into the market at prevailing market prices. If the market price is above the average cost of gas in the portfolio, the "buyer" will record a profit on the transaction. But if the market price is below the average cost of the portfolio, the "buyer" can suffer a loss.

Contracts and a "Balance Business Book"

One approach to managing volume risk attempt is to balance gas purchase obligations with contracts to sell the same volume of gas at similar prices. If the gas buyer in our example is a marketer, he or she could enter into a contract with one or more end-users where the end-user commits to purchase a specific volume of gas. The marketer would then mange the gas purchase portfolio to "balance" their overall position in the gas market or "book." If a marketer has more obligations to buy gas than contracts to sell gas, they are said to be "long" on gas. If the marketer has more contracts to sell gas than obligations to buy gas, they are said to be "short."

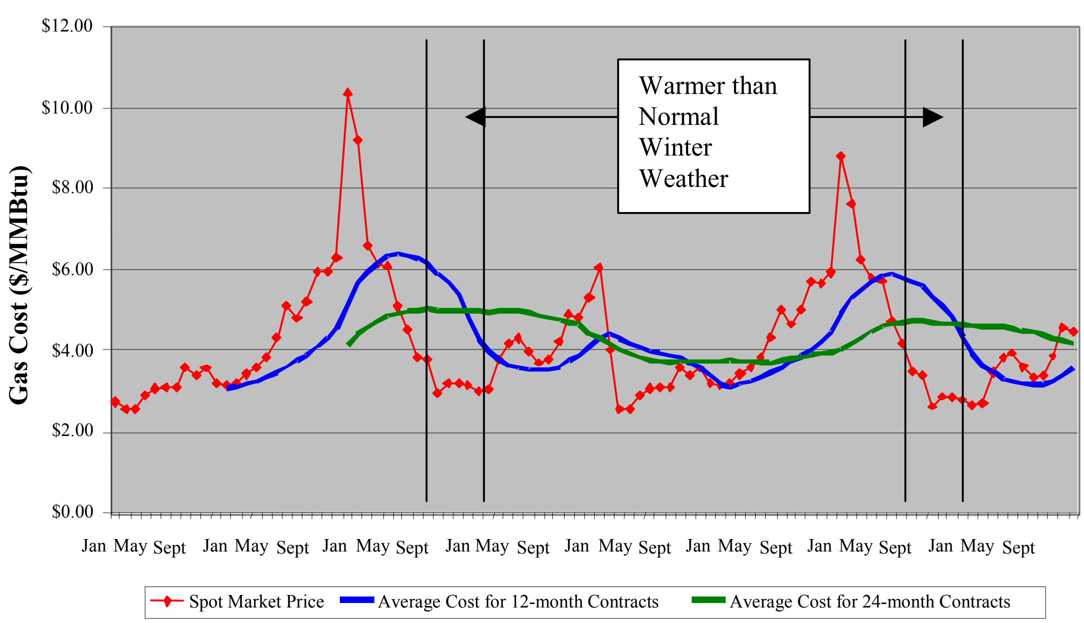
For a marketer to make money on a "balanced book," the marketer would need to have a difference or "margin" between the average gas purchase price in their portfolio and the average price in the contracts to sell gas. With intense competition between marketers, it is difficult to sustain a margin of any significant size.

Correlation of Price and Volume Risk

Volume risk can be quite problematic for an LDC or retail gas marketer that serves temperature-sensitive load. For these gas buyers, warm weather can cause gas requirements to fall significantly below forecasted levels. Moreover, if the weather is warmer than normal for one LDC, it is warmer than normal for all LDCs in the region. With lower total demand, prices are likely to be relatively low as well. This is precisely the behavior observed in the example presented. (See Figure 4-2)

Figure 4-2

Comparison of Spot Market Price with " Laddered" Portfolios



In the Chicago price data used to construct the example, the high price winter periods were constructed based upon prices during the cold weather experienced in winter of 2000-01. The relatively low price winter periods were constructed based upon the warm winter of 1999-00. The price increases observed in the winter of 2000-01 were driven by generally tight supply conditions combined with weather driven increases in gas demand.[6]

Because the requirements of an individual LDC or retail marketer are correlated with total gas consumption, they also tend to be correlated with price. As the figure shows, an LDC or retail gas marketer that entered into longer-term supply contracts to fully hedge forecasted[7] requirements would be expected to have to sell gas at a loss during warmer than normal winters.

Hedging Costs

Moreover, hedging activity incurs additional costs. In addition to the staffing overhead costs directly related to the hedging activity (including accounting activity and risk management oversight), there are direct costs including fees for hedge products, such as futures, options, swaps and collars. As a result, a "fully hedged" gas supply portfolio does not guarantee that the gas is acquired at the lowest possible price. In fact, because of the transaction and administrative costs associated with hedging, over the long-term the expected cost of a hedged gas supply portfolio will be slightly above average of the market price for gas over the same period.

Correlation of Gas and Electricity Price Risk

The correlation – or lack of correlation – between electricity prices and gas prices are important elements of the economics and risks of installing distributed generation, particularly in an application that expects to sell some or all of the electrical output to the grid. In a companion volume to this report entitled *Impact of Energy Price Volatility on Emerging Markets*, the nature of the relationship between gas and electricity prices was discussed.

Summarizing the conclusions, the correlation between gas price and wholesale electricity market prices is a function of the amount of non-dual fuel gas capacity that is included in the generation mix. Generators bid and the marginal clearing price for the electricity will be based upon the cost of generating electricity in the power plant with the highest operating costs included in the generation mix. Since gas-fired generation is often the marginal cost unit, the electricity price often will reflect the cost of the least efficient gas-fired unit in the generation mix.

Implication for Distributed Generation

In the case of distributed generation, the economics of the decision to install has less overall market risk when electricity prices and gas prices are highly correlated. When the prices are correlated, increases in the cost of gas are reflected in increases in the price of electricity, thus

6 A complete description gas market conditions and gas price behavior is contained in Chapter 1: *Price Volatility in Today's Energy Markets.*

7 This assumes that the forecasted requirements were based upon "normal" weather.

the value of the electricity output covers the cost of the input. The risk to a DG application may be greatest during periods of high gas prices combined with modest and stable electricity prices. Under these conditions, the electricity output is less economic than purchasing electricity from the grid.

As a result, ironically, hedging a gas purchase portfolio can actually increase overall market risk for distributed generation under certain conditions. Specifically, since a hedged gas supply portfolio can diverge from the "market" price, the hedging activity can decrease the correlation between the gas price and the wholesale market electricity price. In most of the applications for distributed generation, however, an increase in market risk is more than offset by cost predictability, budget certainty, and planning advantages afforded by a hedged gas supply portfolio.

4.2.1.3 Regulatory Risks Associated with Hedging Activity

As regulated entities, gas LDCs face a number of issues in considering whether to engage in hedging activity to reduce price volatility that are not faced by unregulated entities. These issues arise from two fundamentals of utility regulation:

1) Prudence review – Traditional utility regulation allows for "after the fact" review of utility costs, subjecting utilities to potential disallowance of costs already incurred.

2) Tariffs with restrictive conditions – Utility service is generally specified by a tariff that carefully describes the terms and conditions of service and limits the utility in terms of the flexibility it has to negotiate the details of a service or its price.

3) Non-discriminatory service requirement for "similarly situated" customers – The application of this requirement limits the ability of a utility to "segment" the market. As a result, a utility may not be able to offer different prices and services to customers that have different characteristics and needs.

Pre-approval vs. Retroactive Review

Over the past two years, a number of gas LDC have approached Public Utility Commissions (PUCs) requesting that the Commissions approve certain parameters for its hedging activities. The utilities have sought approval with the following objectives:

- To limit the risk of disallowance of the costs of the hedging activity;

- To determine the applicable accounting methods to be applied if financial derivatives are used, and;

- To limit the risk of "second guessing" by regulators if market prices turn out to be below the "locked-in" gas price of the hedged portfolio.

Intervening parties argued that a Commission should not pre-approve any plan unless and until it can be demonstrated that the program provides consumer benefits.[8] In addition, parties have argued that a utility hedging program would reduce the ability of unregulated marketers to compete with the utility.[9]

Throughout their history, state PUCs have been reluctant to restrict themselves or future commissions from exercising certain actions that may be deemed appropriate in the future. Intervenors argue it is inappropriate for the Commission to fully commit itself up-front to a utility's actions given that market conditions may evolve in a manner rendering the pre-approved plan imprudent.[10]

At the same time, some utilities have been criticized for not hedging a sufficient gas volume. In the wake of the high gas prices in the winter 2000-01, an intensive review of purchase practices ensued. The Staff of the Missouri Public Service Commission argued that the LDCs in the state should have hedged a minimum of 30 percent of its projected gas requirements and that some costs be disallowed for insufficient hedged volumes. The utilities responded that it is not reasonable to be held to a minimum hedging threshold that was established only after the gas costs were incurred and, therefore, not known to the utility at the time the purchase decisions were made.

The objective of a hedging program is to provide price stability and predictability. This is achieved by "locking in" future prices with a combination of physical and financial tools. As noted above, a hedging program does not guarantee that the price of the gas will be minimized. In contrast, the premise of traditional gas cost prudence review is that gas costs be minimized based upon the information that was available at the time that the decisions were made.

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8 For example, earlier this year in Maine a Hearing Examiner rejected a hedging plan proposal by Northern Utilities. The proposal called for the approval of a hedging plan that would include futures contracts as a means of reducing the volatility of the price of natural gas. The proposal also requested that any transaction costs incurred in the purchase of futures contracts, as well as any cost of administering the program, be fully passed on to the utility's customers. In her report, the Hearing Examiner argued that the proposal "amounts to pre-approval of the added costs of a hedging plan that may not provide any benefits for ratepayers and does not contain performance incentives for the utility." The state's public advocate argued that weak incentives would result in the utility passively managing the hedging program, contending that "[c]ontinuous oversight and management of a hedging plan is necessary and will be fostered only when the Company shares in both the costs and benefits." The public advocate also argued that the program does not require pre-approval from the Commission, and that consumers may not be willing to pay the cost that would be required of them for having price stability

9 In a Massachusetts proceeding, marketers and the state's Attorney General criticized Bay State Gas' proposed hedging plan. They argued that the proposal would weaken competition and has the potential to harm customers as well by raising gas costs. The Attorney General asserted that the Commission should allow the competitive market to provide gas sales services with capped prices or any other pricing variations, created with or without hedging.

10 In a separate Commission investigation in Massachusetts, the Attorney General strongly recommended against allowing LDCs to hedge with financial derivatives. Among other things, the Attorney General argued that hedging with financial derivatives has not been shown to provide net benefits to consumers and that hedging can produce "huge" losses.

These differing objectives creates tension between an LDC and the state Public Utility Commission (PUC) if the LDC adopts a strategy to address gas price volatility that involves hedging. In cases where an LDC locks in prices that are higher than the actual market price turns out to be, the LDC runs the risk that a portfolio will be "out of the market," with the potential for subsequent cost disallowance as part of a prudence review of gas purchase costs. As a result, without pre-approval of a hedging program, traditional utility regulation creates a strong incentive for an LDC to manage its gas supply portfolio so that it closely tracks market prices.

Volume Risk from Customer Migration

LDCs can also face additional volume risk derived from the structure of a customer choice program. Customer choice programs in a number of states offer considerable flexibility for customers to migrate to alternative gas suppliers and return to the utility for regulated service. In those states that set some restrictions on migration and return, the restrictions are prescribed in the tariff and the utility has little or no ability to adjust to the restrictions without Commission approval.[11]

As a result, a utility with a customer choice program has an additional inherent uncertainty in forecasting gas requirements. If a utility hedges a large percentage of its projected requirements and a large number of customers migrate to alternative suppliers, the utility may find that it has committed to buy more gas than it needs. As a result, the utility is exposed to the risk that market price is below the price of the hedged portfolio in this instance.

Moreover, the volume risk from customer migration can be correlated with price risk, creating even greater total risk. If the utility has entered into long-term contracts or hedged in some other manner to provide price stability and market prices fall, alternative service providers will have a price advantage in the eyes of prospective customers, thereby increasing the rate of migration.

Finally, the utility is likely to be prohibited from taking the actions that an unregulated supplier is likely to adopt in this situation. If an unregulated marketer were faced with this situation, the marketer would likely analyze their customer base and potential customers and segment the market according to those customers that are most likely to be lost to competition. The unregulated marketer could reduce the price offered to these customers, while maintaining the higher price to the customers that are contractually committed, only offering the lower price to those customers upon contract expiration. In most instances, the utility is prohibited from adopting this strategy because all of the customers in the same rate class must be charged the same rate.

[11] For example, a number of choice programs prohibit a migrating customer from electing to return to utility service for a period of at least one year. Another approach is to establish "open seasons" during which customers can choose alternative suppliers.

4.2.2 Service Offerings Designed to Reduce Price Risk for End-Use Customers

Because energy marketers and LDCs have tools to hedge price risk, they are capable of designing service offerings that provide end-use customers some protection against price volatility risk to end-use customers. The objective of these service offerings is to meet a customer's perceived need or preference for predictable and stable prices without subjecting the service provider to unacceptable price risk.

All of the major retail gas and electricity marketers and most small marketers offer customers fixed-price service options. Marketers perceive a fixed-price offering as an effective tool in capturing market share. However, these programs can present significant risk to the marketer. Complete hedging of both the price and volume risk for temperature sensitive gas or electric load can be very expensive. As a result, many marketers hedged only a portion of the risk in an attempt to increase profitability. However, during the 2000-2001 winter heating season, the gas price increase along with the volume increase resulted in major losses for many of the marketing companies. The losses contributed to the bankruptcy of a significant number of retail marketers and caused a number of other retail marketers to withdraw from the business.

By contrast, few LDCs have such service alternatives. Only a handful of utilities offer fixed-price service alternatives. In addition, at least one utility offers a capped-price option in addition to the fixed-price option. A fixed-fee is charged to customers choosing the capped-price option. The fee is related to prevailing option prices, which can be as high as 20 to 25 percent of the gas costs during periods of high volatility. One Midwest utility received approval to offer a fixed-bill offering as part of a pilot program in addition to a fixed-price offering. However, the fixed bill option was withdrawn.

Most of the fixed-price service offerings by marketers or LDCs require the customer to make a contractual commitment to the service offering for a one-year period. This limits the risk that the customer will leave the service if prices fall and leaves the service provider with gas purchase commitments that are above the market price.

Fixed-price options can be extremely difficult for LDCs to structure given the restrictions placed on programs by state regulators. The programs require the ability of the utility to "stream" gas supplies to specific customers.[12] Moreover, the programs can result in over-collection or under-collection of gas costs. LDCs can be at risk for differences if there is asymmetric regulatory treatment.

Moreover, it is not clear how much value customers place on fixed-price service. Customer participation in choice programs are relatively low. LDCs that have such offerings find that only 5 to 10 percent of customers participate. Nationally only 12 percent of customers that are

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[12] "Streaming" refers to the creation of a dedicated gas supply that is priced separately from the portfolio used to serve "core market" customers.

eligible – *but not forced* – to participate in customer choice programs actually do so.[13] The relatively low participation rate suggests that many customers do not consider the opportunity for a fixed-price service option to be sufficiently attractive to justify changing service providers.

[13] Data published by the American Gas Association in May 2002 indicates that 21,319,813 customers were eligible to participate in choice programs. Of these, 3,888,648 chose an alternative supplier. However, of these, 1,459,700 were in programs that required all customers to migrate to alternative providers. Only 12.2 percent that had the option to remain with LDC sales service chose to migrate to an alternative supplier.

4.3
Specific Strategies for Managing Price Volatility

4.3.1 Strategy Options for LDCs and Energy Holding Companies

The strategies presented in this section are designed to assist a regulated LDC or its holding company to manage price risk in a volatile market environment. They represent a series of options that may be considered and are not recommendations. Whether or not any of the strategies is appropriate for an individual company must be determined on a case-by-case basis.

4.3.1.1 Strategy 1: Regulatory Pre-approval of Multi-year Hedging Activity

Objective: Provide stability in gas commodity prices while limiting the risk of being "second guessed" in a regulatory prudence review.

Description: The LDC initiates a proceeding or collaborative with the PUC and other stakeholders. The objective of the proceeding is to: 1) establish parameters guiding hedging activity; 2) determine the procedure for adjusting the parameters, with the adjustments evaluated prospectively from the time the adjustment is made; and 3) specify the procedure for record keeping and accounting for the hedging activity.

Rationale: There is no single level of hedging that is inherently the "right" amount to hedge. Neither the LDC nor the state's regulators can know precisely how much of a gas supply portfolio should be hedged. This is because the "correct" amount of hedging reflects the amount of additional costs that customers are willing to pay for stability in gas prices and as insurance against unanticipated increases in gas prices. In a regulated market, the Commission should act on behalf of the LDC's customers to provide guidance in determining how much of the LDC gas supply portfolio should be hedged. The only way that a reasonable program can be designed is for the LDC and its regulators to define, in advance, the objectives and parameters of a hedging program.

Pros: The strategy allows the utility to make a case for an appropriate program and creates a record that can be used to defend against *ex post facto* review of the program. Pre-approval allows the utility to argue that the prudence review should be limited to the prudent execution of the program and not the parameters of the program itself.

Cons: The strategy can invite the regulators to become more closely involved in the day-to-day management of gas supply.

A hedged portfolio can expose a utility to significant additional volume risk.

A hedged portfolio can create additional price risk if the utility has "performance-based" incentives as part of the gas acquisition regulation, particularly if the incentives are tied to market index prices.

Implementation Barriers: Regulators have been reticent to restrict their future actions. In a number of instances, the regulators have declined to grant pre-approval.

4.3.1.2 Strategy 2: Multi-year Fixed Price Service Option for Combined Heat and Power Customers, or Other Segmented Customer Classes

Objective: Segment the market to allow for a customized service to CHP applications. Natural gas is delivered at fixed price for multiple years and is combined with a contractual commitment from the facility owner for most or all of the period. A particular focus should be on new facilities, which would foster penetration of the technology.

Description: The LDC would file with the PUC for a new optional tariff service for CHP applications. The tariff should allow the LDC to "stream"[14] a dedicated gas supply to the facility with prices set by contract. Since the customer also has the option to elect the standard tariff service, the LDC can argue that the standard service is a "recourse" option.

Pros: By segmenting the market, CHP customers are recognized as a separate customer class. The customized service offerings would allow the utility to develop the CHP market and meet the specific needs of their customers.

"Streaming" remains a cost-based gas supply portfolio for CHP customers and the offering does not affect the gas cost of other customer classes.

"Streaming" combined with the contractual commitment allows the utility to maintain a balanced business book for CHP customers as the market grows.

The non-gas portion of the tariff rate can continue to be determined using existing mechanisms.

Cons: It may be difficult to differentiate CHP gas load from other applications at the same location without dual metering.

[14] "Streaming" refers to the creation of a dedicated gas supply that is priced separately from the portfolio used to serve "core market" customers.

The approach will require additional marketing resources since it involves customized marketing and client support. The strategy may also require changes to billing systems so that the bills reflect the correct gas costs.

A focus on CHP or other specific technology may leave other opportunities unexploited without further segmentation and streaming.

Implementation Barriers: Regulatory precedent developed before the commoditization of natural gas viewed streaming as discriminatory and preferential. The barrier set by this precedent may be difficult to overcome. However, the basis of the historical objection, that streaming allowed selected customers preferential access to "lower price" sources of supply, might not apply in a market environment where gas is a fungible commodity traded at various liquid market centers.

4.3.1.3 Strategy 3: LDC Provides Non-Discriminatory Transportation Service that Allows Unregulated Entities, Including an LDC Affiliate, to Craft Segmented Service Offerings to Distributed Generation and Other Market Segments

Objective: Allow unregulated merchants to compete, providing the incentive to offer tailored gas supply services.

Description: The LDC would file with the PUC for a transportation tariff service suitable for DG customers including CHP applications. The unregulated marketer performs the gas supply management function and has the option to "stream" a dedicated gas supply to the facility with the price set by contract. Competition in the marketplace will determine the success of fixed price offerings. The LDC is able to present to the Commission that the unregulated affiliate provides alternatives to consumers and that non-discriminatory tariffs and codes of conduct can provide adequate protection from the transfer of market power from the transportation function to the merchant function.

Pros: The strategy is consistent with the unbundling programs in most states.

Price volatility risk is principally borne by the unregulated merchant and the customer with risk allocations defined by contract and negotiation.

Cons: State unbundling proceedings offer the opportunity for intervenors to inhibit the LDC affiliate from competing successfully or to transfer costs to the regulated utility.

To the extent that the LDC remains a "supplier of last resort," the LDC may incur costs and be subject to price risk. These issues can become quite severe in the event of a bankruptcy of a major retail marketer in the service territory.

Implementation Barriers: Currently, the financial health of many unregulated marketing companies is problematic and it is unclear when – or if – these companies will return to a healthy state. It may be some time before marketing companies are in a position to absorb the credit risk associated with offering long-term fixed price offerings, even when the liabilities are "backed" by purchase contracts.

Investors are disenchanted with energy marketing, therefore making large-scale development of the sector difficult.

4.3.1.4 Strategy 4: Develop Integrated Gas Supply and Diversified Electric Generation Supply Portfolio

Objective: Integrate the contractual and physical assets to create economies of scope and scale. Diversify so as to reduce the amount of correlated price risk.

Description: A utility or holding company works to create a broad portfolio of physical and contractual assets. The gas supply portfolio could include gas reserves as well as purchase contracts and transportation capacity. The electric generation portfolio should have diverse fuel sources (such as oil, coal, and hydropower) and include both central station units and distributed generation assets.

Pros: A large and diversified portfolio is a natural hedge against price volatility. If natural gas prices rise, the value of non-gas fired generation increases.[15]

Cons: The strategy requires large amounts of capital and therefore may not be appropriate for medium or small companies. In addition, the need for more capital can lead to a higher debt to equity ratio, thus leading to increased credit crunch.

Efficient management of a large portfolio can become difficult. Loss of efficiency and a lack of synergy can result in under-performance and a significant loss in shareholder value.

15 When gas prices increase, the wholesale price of electricity also increases during peak periods when gas is fueling the generation of electricity. The operating costs of non-gas fired generation are unaffected or, in the case of oil fired-generation, affected to a lesser degree. As a result, the difference between the operating costs and the average price of electricity increases, providing increased returns on the generation portfolio.

Implementation Barriers: Currently, capital markets are extremely tight and it remains unclear as to how long the condition will persist. Moreover, many of the large companies are shedding "hard" assets to shore up their balance sheets and are not in a position to solidify a portfolio. Finally, equity markets are severely punishing companies that show any risk of under-performance.

4.3.1.5 Strategy 5: Develop Storage Assets and Optimize Utilization in the Regional Gas Market

Objective: Develop strategically located storage assets and obtain the necessary regulatory approval to optimize the utilization of the storage assets.

Description: The value of storage extends well beyond being a source of reliable winter supply.[16] While significant progress has been made, there remain significant structural and regulatory impediments to creating additional economic value in the gas marketplace. The LDC would file proposals asking the PUC to grant the utility additional flexibility in the operation of existing assets and petition the FERC to review jurisdictional storage tariffs to seek to remove any unnecessary operational restrictions. New storage facilities should apply market-based rates or banded rates in markets that are not highly concentrated[17], so long as the storage provider is placed "at risk for the recovery of the cost of storage the storage facility". This would provide incentives for the development of storage assets by parties other than interstate pipelines and allow these facilities to be profitable by capturing rates above the cost of service rate in some years to offset underrecovery that occurs during warmer than normal years.

Pros: Storage can serve to reduce the magnitude of price spikes in a regional gas market. The strategy would encourage the construction of additional storage and the entry of additional participants in the market for storage.

New storage, particularly high deliverability storage, can provide important operational benefits in managing the natural gas network with an increased power generation load.

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16 Nevertheless, storage continues to serve an important role in assuring reliability of service. Moreover, storage will continue to serve that function for the foreseeable future.

17 Market concentration is a measure used to evaluate the ability of a participant to exercise market power. Concentration generally measured with a Herfindahl-Hirshman Index (HHI) = $\Sigma(s_i)^2$ where s_i is the market share, as a fraction, of the i^{th} firm. The HHI takes a maximum value of "1" in the case of monopoly (the market share of the single firm is 100% or "1", and $1^2 = 1$), and takes a very small value when the market is characterized by a large number of firms with similar market shares. In the context of natural gas regulation, FERC uses a HHI value of .18 or below as the threshold level for less scrutiny.

Cons: During periods of warmer than normal weather, the value of storage capacity can be quite low. A series of consecutive warm winters could devastate the value of storage and the "at risk" conditions would prevent the recovery of the cost of the facility under Base Rates.

Implementation Barriers: While FERC and the Ontario Energy Board have granted flexibility in storage rates and services, PUCs in the United States have not demonstrated a willingness to do so. State jurisdictional LDCs may find it difficult to obtain the flexibility needed to operate more efficiently in the regional gas market. Many states limit an LDC's ability to use storage to serve off-system customers.

4.3.1.6 Strategy 6: Develop Delivered Energy Service Options for Electricity Load Where the Service Provider Owns and Operates the Energy Production and Delivery Assets Including Distributed Generation

Objective: Market delivered energy to large and mid-size energy consumers using a portfolio of energy assets owned by the service provider.

Description: The service provider, or an unregulated affiliate, develops and owns assets to manage the delivery of energy gas, electricity and other requirements to customers. The asset portfolio would include CHP and other distributed generation technologies with multiple fuel sources to generate the electric energy requirements for all of their customers as well as providing other delivered energy. The objective of the strategy is to have a diversified portfolio of options to generate electricity combined with a gas load in an area that is subject to both electricity transmission constraints and gas transportation constraints. The service provider uses the portfolio of assets to arbitrage changes in the relative prices of different energy types in the market area while collecting base load revenue from the end use customers for financing developing and maintaining the equipment on the customers premises. The strategy is most valuable in an environment with extremely volatile energy price environment.

Pros: The strategy presents arbitrage profit opportunities without some of the credit risk associated with a pure trading operation. The strategy also ensures a stable revenue in the form of service fees.

Cons: The strategy places the service provider at risk from a change in the nature of the energy market. For example, if new electric transmission of pipeline capacity were constructed, the arbitrage opportunities would be reduced significantly. Moreover, in such an event, the service provider might be less competitive in the regional market. The provider could be forced to discount the cost of the service to the end users, thereby decreasing margins.

Implementation Barriers: The strategy requires favorable interconnect policies and at least some level of retail electric choice in the market area. Over the last several years, many states have delayed or abandoned retail electricity choice programs and the momentum is moving away from this regulatory model.

4.3.1.7 Strategy 7: Increase Prearranged Buyback Programs with Large Volume Gas Consumers

Objective: Increase the incentive for large volume industrial and power generation customers to take advantage of pre-arranged buyback contracts.

Description: Over the past 15 years, most large volume gas customers have converted from gas sales service to transportation service. This has made the process of managing gas supplies somewhat more difficult for the LDC. During period of high demand and tight supplies, most LDCs attempt to buy back gas from transportation customers. Prearranged commitments to sell supplies facilitate these arrangements. The strategy would provide for an incentive for large volume transportation customers to enter into such arrangements. The LDC would file a proposal with the PUC to allow for payments at the time that the LDC and the customer enter into the agreement. The payment would provide an incentive to large volume customers to participate. The agreement would also contain a provision whereby the large volume customer would be required to pay an amount equal to the payment plus a penalty in the event that the customer cannot honor the commitment to deliver the gas to the utility. The objective is to provide a guaranteed payment with the capability to deliver.

Pros: The strategy would provide an additional element to the LDC's supply portfolio.

The strategy would increase demand response, thereby serving to decrease volatility. (See Section 4.2)

Cons: The strategy raises issues of cost recovery and lost revenue for the LDC.

At the time that the utility requires the gas committed under the prearranged deal, the transportation customer could be experiencing difficulty with their marketer, and transportation customers would be subjected to the penalty.

Implementation Barriers: PUCs may be reluctant to approve a payment for a contingency that may not occur.

4.4 Strategies, Policies and Approaches that Reduce Energy Price Volatility

This section is intended to discuss strategies and policies that affect energy price volatility and market fundamentals. Unlike the strategies presented in the earlier section, an individual company cannot implement the options presented here. Rather, any change from status quo would require legislative or regulatory changes that would affect a broad range of parties.

Several of the alternatives discussed here have been included in the policy recommendations of a number of diverse organizations or in various proposals that were considered as part of the energy legislation put before the United States Congress in 2002. The fact that some of these recommendations and proposals are included here while others are not should not be construed as an endorsement of any policies. Rather, the inclusion of the recommendations and proposals reflect an analytic conclusion that the proposals could have a direct impact that reduces expected volatility. However, there are many other effects to consider that are beyond the scope of this research. As such, the inclusion of a particular option should in no way be considered an endorsement of the policy by the authors or sponsors of the study.

4.4.1 Status Quo

It needs to be recognized that largely maintaining the status quo is an option and may be a likely outcome. Many of the alternatives available would require additional investments from some parties or increase the costs of some services. As such, one should recognize that it may be quite difficult to obtain the necessary consensus to implement any of the alternatives discussed.

4.4.2 Strategies that Increase Demand Response

As discussed in this report,[18] demand elasticity – or the lack thereof – is an important factor in determining the volatility of prices. Under certain market conditions, very large price movements are necessary to evoke the relatively small demand responses needed to balance supply and demand. This can be particularly true in natural gas and electricity markets where much of the demand curve is highly inelastic.

Consequently, strategies or policies that increase the magnitude of the demand response to changes in price can fundamentally decrease price volatility in a fundamental way. Analysis

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18 *Price Volatility in Today's Energy Markets* and *Outlook for Future Natural Gas and Electricity Price Volatility*

Table 4-1
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	6,750	5,806	5,964	5,959	5,935
CHP/DG	698	998	1,298	1,598	1,898
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	2,066	2,851	3,524	3,952
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Total Industrial	**682**	**740**	**799**	**857**	**916**
Boilers	546	546	546	546	546
Process Heat/Other	1,265	1,088	1,118	1,117	1,112
CHP/DG	136	194	253	311	370
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**	**1,238**	**1,686**	**2,060**	**2,268**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Total Industrial	**341**	**370**	**399**	**429**	**458**
Boilers	273	273	273	273	273
Process Heat/Other	316	272	279	279	278
CHP/DG	68	97	126	156	185
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

indicates that the following policies would have the potential to increase the magnitude of demand response.

By far, the largest potential source for additional demand response capable of adjusting to short-term imbalances of supply and demand are the applications capable of switching from gas to oil. Table 4-1 presents data that can be used to estimate the amount of additional fuel-switching potential that could technically be developed. The data indicates that by 2010 more than 1 Tcf of additional potential supply response could be created with increased dual-fuel capability. By 2020, the total potential increases to 1.5 Tcf.

4.4.2.1 Strategy 10: Establish Minimum Requirements for Dual Fuel Capacity for Gas-Fired Electric Generation

Objective: Increase the amount of electric generation capacity that can switch between gas and oil based upon the relative prices and availability of the two fuels.

Description: Gas-fired generation built in the last five years and under construction today has substantially less dual-fuel capability than the older vintage of gas generation. While the new combined cycle and combustion turbine technologies are not capable of burning residual oil, there is no technical impediment to burning distillate oil.

The strategy is designed to provide an incentive to invest in dual-fuel capability in new plants and to retrofit some of the plants built over the past several years. Differentiating between dual-fuel capacity and single-fuel capacity in the evaluation of a state generation resource plan or in any resource adequacy requirement could create the incentive to invest in the capability.

Pros: The strategy would diversify the portfolio of electricity production assets while adding to the demand response in electricity markets. The result would be to reduce price volatility in both markets.

The costs of dual-fuel capability are a relatively small portion of the total capital cost of a generation plant. Therefore, the additional investment required is not prohibitive.

Cons: The strategy would penalize generation in urban and suburban locations where obtaining the land and land use permits for oil handling facilities would be more difficult.

The strategy could increase distillate oil price including home heating oil during winter heating season.

Implementation Barriers: Implementation of the strategy at the state level would increase already disparate standard within control areas used to determine dispatch of generation. The strategy would be most effective if it were implemented on a national or regional basis. As a result, implementation would be embroiled in the broad debate surrounding the FERC Notice of Proposed Rulemaking for Standard Market Design (SMD).

4.4.2.2 Strategy 11: Implement Electricity Demand Response Programs as Part of the Structure of Regional Transmission Organizations

Objective: Increase the penetration of "demand response" programs in additional markets and expand participation in those markets where they exist.

Description: "Demand response" refers to the demand-side participation in the wholesale electricity market and includes direct load control[19] and price responsive load. Demand response programs have been in operation in all four operating ISOs[20] and are considered an important component in the successful operation of an RTO. The programs can be categorized either as bid-based programs or programs where the load is a "price-taker."

The strategy involves the development of additional incentives for participation and strengthens the requirements for demand response to be included in Standard Market Design. The strategy would include state or rate-based funding for enabling technologies such as interval meters and load control equipment. The strategy would also include advanced payments for participating load, particularly load that is participating as a "price-taker."

Pros: The strategy would directly increase the demand response in the electric market. In addition, the programs would indirectly increase demand response in the gas market by reducing the need for peaking generation units to bid up the price of gas.

Cons: The strategy raises issues of cost recovery and lost revenue for the utility and gas providers.

The strategy raises issues of cost causation and whether the costs should be socialized across multiple Load Serving Entities (LSEs) or system-wide.

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19 Direct load control such as control of air conditioners and water heaters by the utility, partial load reductions and curtailments.

20 California ISO, New York ISO, ISO New England, and PJM.

Implementation
Barriers: As in the case of SMD, a series of jurisdictional issues are raised. For example, does FERC have the authority to create a market for load reduction?

4.4.2.3 Strategy 12: Implementation of Dynamic Pricing for Price Sensitive Electricity and Retail Gas Customers

Objective: Provide customers with awareness of market price signals in a timely manner and create an incentive for participants to respond to the market signals.

Description: A major impediment to the development of demand response is the existence of rate structures that do not respond to changes in market prices. Customers have little incentive to adjust consumption patterns if their bills are not significantly affected.

The strategy will eliminate regulatory mechanisms that "smooth" prices to large volume, price sensitive customers. This change in regulation would not affect residential and small commercial customers since these customers have significantly less ability to adjust consumption. In addition, exempting these customers would avoid the costs involved in installing time-of-use meters for these classes of customers.

Pros: The strategy would directly increase the demand response in gas and electric markets thereby reducing the likelihood and magnitude of price spikes.

Cons: The strategy raises issues of cost recovery and lost revenue for the utility and gas providers.

In markets where customer choice programs are available, the shift in pricing could result in increased migration to unregulated providers that provide price stability.

Implementation
Barriers: Customer resistance could make it difficult to obtain the needed consensus.

4.4.3 Strategies that Increase Infrastructure and Supply Response

As discussed in other chapters[21], increasing energy infrastructure to create a "reserve margin" of available supply can reduce energy price volatility. Once all of the available sources of energy supply are being fully utilized, increasing prices will not make any additional supply available in

[21] *Price Volatility in Today's Energy Markets* and *Outlook for Future Natural Gas and Electricity Price Volatility*

the short-term and the market must be balanced solely on the basis of the demand response. Analysis indicates that the following policies could create a "reserve margin" in the supply of gas and/or electricity.

4.4.3.1 Strategy 13: Implement Floor Prices above Variable Cost on Interruptible Pipeline Transportation

Objective: Increase the contribution of interruptible shippers towards the fixed cost of a natural gas pipeline.

Description: The strategy is similar to the regulatory framework currently in place on the TransCanada Pipeline. Regulation establishes a floor price well above the variable cost of transportation. Any increase in IT revenues that results in overrecovery would be credited back to the firm shippers.

Pros: The floor price would also support the market price of capacity release thus benefiting firm shippers.

Cons: The floor price could decrease throughput offsetting the potential revenue increase expected from the higher price.

Implementation Barriers: Producers and interruptible shippers would likely object to floor price, thereby making it difficult to gain consensus.

4.4.3.2 Strategy 14: Return to a Natural Gas Pipeline Rate Design that Reduces Demand Charges and Increases the Volumetric Component of the Rate

Objective: Increase the contribution of interruptible shippers towards the fixed cost of a natural gas pipeline and reduce the cost of firm transportation contracts.

Description: Historically, pipeline rate design has been used to adjust the incentives regarding new pipeline construction. Reducing the demand charge component increases the demand for firm capacity by shifting risk from the shipper to the pipeline. An increase in demand supports new construction by increasing the level of commitments for the new projects.

Pros: The decrease in the demand charge would reduce the risk to firm shippers and attract more power generation customers to firm service.

Cons: The floor price could decrease throughput offsetting the potential revenue increase expected from the higher price.

Implementation
Barriers: Producers and interruptible shippers would likely object to the floor price making it difficult to gain consensus.

4.4.3.3 Strategy 15: Augment Electric Generation Resource Adequacy Requirements to include Assessment of Fuel Portfolio Assets

Objective: Provide an incentive for power generators to enter into long-term gas supply contracts and firm transportation contracts on gas pipelines.

Description: In the Notice of Proposed Rulemaking, FERC has proposed a resource adequacy requirement for all electric Load Serving Entities (LSEs). The objective is to ensure that LSE have identified sufficient generation capacity and taken steps to build or contract for capacity to meet their load. The proposal is to differentiate between gas-fired capacity that have entered into firm commitments to buy and transport their fuel and those that have not. The strategy would require a larger capacity margin for LSEs that rely on gas firmed capacity with less than firm gas supply.

Pros: The strategy would foster long-term contracts with gas producers thereby reducing the risk of exploration and development to at least some degree.

The strategy would increase the amount of firm transportation pipeline capacity contracted by power generation customers thereby supporting additional pipeline construction.

Cons: The requirement would increase the cost of gas-fired generation relative to coal and other alternatives.

Implementation
Barriers: Implementation would be embroiled in the broad debate surrounding the FERC Notice of Proposed Rulemaking for Standard Market Design (SMD).

4.5 Conclusion

Strategies designed to address volatility fall into two categories: 1) Strategies and policies that are designed to reduce volatility including a reversal of the trend in regulation that has inhibited long-term contracts and investment in supply facilities, and 2) Strategies that are designed to manage volatility and allocate the risks associated with volatility.

Strategies and policies that are designed to reduce volatility

Strategies and policies designed to reduce volatility create incentives or regulatory requirements to invest in facilities that increase the availability of "reserve supply" capacity or increase the amount of demand that is shed in response to increasing prices. Returning to a greater use of longer-term contracts could be an effective method of financing the infrastructure required to supply the reserve supply capacity needed to moderate price volatility.

During restructuring over the last several decades, policies that foster price stability through long-term contracts and investment in facilities that provide a reserve supply capability were often abandoned in favor of policies promoting market efficiency goals with the effect of increasing price volatility. Adopting policies that would provide incentives for increased use of long-term contracts could recreate a balance that would moderate volatility compared to a continuation of current trends.

Strategies and policies designed to reduce volatility must be adopted by a large number of participants to be effective. Without structural changes that create broad incentives or regulatory requirements to make the required investments, an individual participant would incur additional costs compared to their competitors without the ability to affect volatility to a significant degree. Hence individual market participants typically do not undertake such investments on their own without an identified mechanism to recover the cost of the investment. A market structure design that relies solely on market determined basis differentials for the recovery of transmission and distribution infrastructure costs is unlikely to recover the costs of investment in reserve capacity. Similarly, there is no incentive for a producer of natural gas or any other energy resource to voluntarily develop production capacity that is held as reserve supply capability.

Without a cost recovery mechanism, participants often see the reserve capacity requirements as the imposition of unnecessary costs that are at risk. As a result, they generally oppose these types of requirements. Compounding this problem, regulated entities have been directly or indirectly restrained from entering into long-term contracts needed to finance the infrastructure investments that could moderate volatility even if a cost recovery mechanism in regulated rates could be constructed in the structure of utility rates.

It will likely be difficult to achieve consensus on adopting policies to increase demand response or create reserve supply capacity without significant support from the general population. 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.

Strategies that are designed to manage volatility and allocate the risks associated with volatility

There are many risk management tools available that a company can use to manage the risks of price volatility. Moreover, unlike the strategies designed to reduce volatility, individual companies can implement strategies that are designed to manage volatility. However, for regulated entities, such as gas local distribution companies, regulatory approval and/or review of the results of a price volatility management program can be problematic. Risk management and hedging programs are not yet well understood by many regulators. In addition, regulators are often reluctant or unable within existing legislation to "pre-approve" a program. A concerted effort to educate regulators and to engage regulators in discussions regarding hedging is necessary.

To date, regulatory oversight of hedging programs generally has not provided the "pre-approval" of the objectives of programs that is needed to rationally implement hedging strategies. As a result, utilities are at risk for hedging decisions and have limited incentive to allow their supply portfolio to deviate significantly from market prices. As a result, gas consumers have been subjected to greater price volatility than might have otherwise occurred had such approval been in place. A concerted effort to add to regulators' understanding and to engage regulators in discussions regarding hedging is necessary.

Importantly, regulators and customers must understand that risk management programs are likely to result in some increase in costs. Just like insurance, hedging and price volatility management involves a payment to a counterparty that is willing to take the risk of an unfavorable outcome. For regulated energy companies, the company and the regulator should determine the appropriate amount of risk management. The appropriate review for a price volatility management program is the prudent implementation of program that is agreed upon in advance.

Unfortunately, there is no "silver bullet" to address market volatility that is guaranteed to reduce gas and electricity prices in the long-term. Rather, there are real, and in some cases, significant costs associated with all of the analyzed strategies that would increase prices over time, but result in more stable prices in return. It is important that industry, consumers, regulators, and policymakers consider the alternatives in an informed manner to develop a consensus approach to addressing energy price volatility.

5 Impact Of Energy Price Volatility On Emerging Markets

5.1 Introduction

In previous chapters of this report we have examined different concepts and measurements of energy price volatility, provided detailed examples and analyses of specific incidences, and explored the impact of energy price volatility on market participants. In this chapter, we examine whether and how the existence of price volatility in the natural gas and electricity markets affects decisions regarding owning and operating emerging energy technologies -- specifically, distributed generation (DG) equipment and combined heat and power (CHP) systems. We evaluate how volatility impacts the perspectives and actions of end-use customer and energy services companies (ESCOs) as they relate to installation, ownership and operation of DG/CHP systems.

Distributed generation is the strategic placement of electric power generating units at or near customer facilities to supply on site energy needs. Combined heat and power is the generation of electric or mechanical power and thermal energy simultaneously from the same fuel source. Distributed generation projects can be designed to produce electric or mechanical power only, or to produce electric or mechanical power and thermal energy (CHP). DG benefits as compared to power from the grid for energy users may include enhanced reliability, superior power quality, independence from the grid, and lower energy costs. CHP offers individual and societal energy and environmental benefits over electric-only systems, in both central power generation and distributed generation applications. CHP systems achieve increased efficiency in fuel use, reduced emissions of air pollutants and greenhouse gases, and enhanced reliability of the electrical grid. Industrial, institutional and commercial facilities are the principal users of CHP, along with some utilities and independent power producers.

End-use customers and ESCOs making DG/CHP investment decisions may implicitly or explicitly address energy price volatility in the investment/planning context. Price volatility in this sense refers to long-term uncertainty about energy price levels that influences investment planning. This uncertainty has a number of potential implications for investors. For example, it might cause them to delay decisions to purchase appliances and equipment. Or, it might cause them to invest in different types of equipment than they might otherwise, e.g., in a dual-fuel capable system rather than a dedicated-fuel system. The ways in which potential DG/CHP investors could take price volatility into account are varied, from demanding a higher rate of return on a project, to informal considerations of impacts, to neglecting the issue entirely.

The following chapters explore and characterize, in turn:

- DG/CHP technologies, owners and operators;
- owner/operator attitudes, perceptions and actions regarding price volatility with respect to DG/CHP-related activities;
- the economics of DG/CHP systems;
- energy price volatility in DG/CHP markets, and;
- quantitative analyses of DG/CHP ownership and operation.

5.2
The Emerging DG/CHP Market: Technologies and Users

5.2.1 Introduction

There are five types of on-site generation technologies: reciprocating engines, small gas turbines, steam turbines, microturbines, and fuel cells. These technologies, known as prime movers, convert fuel to shaft power or mechanical energy. In both DG and CHP applications, the mechanical energy from the prime mover drives a generator for producing electricity. It may also drive rotating equipment, such as compressors, pumps and fans. In the case of CHP applications, a heat recovery system captures and converts the energy in the prime mover's exhaust into useful thermal energy. The thermal energy from the heat recovery system can be used either for direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling.

Most installed on-site generation today is CHP capacity. Table 5-1 on the following page depicts the current installed base of CHP by type of prime mover and sector. In the sections that follow, we describe the prime mover technologies and applications that are part of the emerging market for DG/CHP and profile briefly potential owners/operators of DG/CHP. Appendix G presents further detail on existing CHP capacity. Appendix H contains tables summarizing the characteristics of the DG/CHP technologies summarized below.

5.2.2 DG/CHP Technologies

5.2.2.1 Reciprocating Engines

Reciprocating internal combustion engines is a widespread and well-known technology, available for electrical power generation applications in sizes ranging from a few kilowatts to over 5 MW. There are two basic types of reciprocating engines – spark ignition (SI) and compression ignition (CI). Spark ignition engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or landfill gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel. Diesel engines have historically been the most popular type of reciprocating engine for both small and large power generation applications. However, in the

Table 5-1
Installed CHP by Sector: 58,931 MW

Prime Mover	Installed CHP Capacity By Sector (MW)			
	Industrial	**Commercial**	**Other***	**Total**
Boiler/Steam Turbine	16,646	1,378	1,038	19,062
Combined Cycle	27,432	2,185	668	30,285
Combustion Turbine	5,724	1,780	2,550	9,854
Recip Engine	232	531	38	801
Other	157	38	11	206
Total	**50,191**	**5,712**	**4,305**	**60,208**

Source: Energy and Environmental Analysis/Energy Nexus Group, Hagler Bailly Independent Power Database

United States and other industrialized nations, diesel engines are increasingly restricted to emergency standby or limited duty-cycle service because of air emission concerns. As a result, the natural gas-fueled SI engine is now the engine of choice for the higher-duty-cycle stationary power market (over 500 hr/yr).

Current generation natural gas engines offer low first cost, fast start-up, proven reliability when properly maintained, excellent load-following characteristics, and significant heat recovery potential. Electric efficiencies of natural gas engines range from 28% LHV for small stoichiometric engines (<100 kW) to over 40% LHV for very large lean burn engines (> 3 MW).[1] Waste heat can be recovered from the hot engine exhaust and from the engine cooling systems to produce either hot water or low pressure steam for CHP applications. Overall CHP system efficiencies (electricity and useful thermal energy) of 70 to 80% are routinely achieved with natural gas engine systems. Reciprocating engines are well suited to a variety of distributed generation applications and are widely used in the U.S. and Europe in power-only and CHP

[1] Lower Heating Value. Most quoted efficiencies are based on higher heating value (HHV), which includes the heat of condensation of the water vapor in the combustion products. In engineering and scientific literature the lower heating value (LHV – which does not include the heat of condensation of the water vapor in the combustion products) is often used. The HHV is greater than the LHV by approximately 10% with natural gas as the fuel (i.e., 50% LHV is equivalent to 45% HHV). HHV efficiencies are about 8% greater for oil (liquid petroleum products) and 5% for coal.

configurations in the industrial, commercial and institutional market sectors. Potential DG applications include standby, peak shaving, grid support, and CHP applications in which hot water, low pressure steam, or waste-heat-fired absorption chilling is provided using waste heat from the engine.

5.2.2.2 Small Gas Turbines

Gas turbines are generation systems operating on the thermodynamic cycle known as the Brayton cycle. In a Brayton cycle, atmospheric air is compressed, heated, and then expanded, with the excess of power produced by the expander (also called the turbine) over that consumed by the compressor used for power generation. Gas turbines can be used in a variety of configurations: (1) simple cycle operation which is a single gas turbine producing power only; (2) combined heat and power operation, which is a simple cycle gas turbine with a heat recovery heat exchanger to recover the heat in the turbine exhaust and convert it to useful thermal energy, usually in the form of steam or hot water; and (3) combined cycle operation, in which high pressure steam is generated from recovered exhaust heat and used to create additional power using a steam turbine. Some combined cycles extract steam at an intermediate pressure for use in industrial processes and are combined cycle CHP systems.

Gas turbines are available in sizes ranging from 500 kilowatts (kW) to 250 megawatts (MW). The exhaust heat from gas turbines is very high-quality and can be used in CHP configurations to reach system efficiencies of 70 to 80%. Turbine-based CHP systems use the turbine exhaust directly for an industrial process such as drying or as input into a heat recovery steam generator that produces steam for process or space conditioning use. The efficiency, reliability and economics of small gas turbines have made them an attractive choice for industrial and large institutional users for CHP applications since the early 1980s. They are also one of the cleanest means of generating electricity. Potential DG applications for small gas turbines in power-only configuration include standby, peak shaving and on-peak systems, and grid support. CHP applications require additional equipment, but are generally a cost-effective DG option when local thermal loads can be met.

5.2.2.3 Steam Turbines

Steam turbines are one of the most versatile and oldest prime mover technologies still in general production. While the capacity of commercially available steam turbines ranges from 50 kW to several hundred MW, on-site power generation uses are in the 500 kW to 20 MW range. Unlike gas turbine and reciprocating engine CHP systems, steam turbines normally generate electricity as a byproduct of heat (steam) generation. Steam turbine systems require a boiler in which fuel is burned to provide heat for steam generation, steam that is then provided to the turbine in the form of high pressure steam that in turn powers the turbine and generator.[2] This arrangement enables steam turbines to operate with an enormous variety of fuels, varying from natural gas to solid waste. In CHP applications, steam at lower pressure is extracted from the steam turbine and used directly in a process or for district heating, or it can be converted to other forms of thermal energy including hot or chilled water.

[2] Steam can also be generated with the waste heat of a gas turbine as in the case of combined cycle power plants.

While steam turbines themselves are competitively priced compared to other prime movers, the costs of complete, "green-field" boiler/steam turbine CHP systems are relatively high on a per kW of capacity basis because of their low power to heat ratio; the costs of the boiler, fuel handling and overall steam systems; and the custom nature of most installations. Thus, steam turbines are well suited to medium- and large-scale industrial and institutional applications where inexpensive fuels, such as coal, biomass, various solid wastes and byproducts (e.g., wood chips, etc.), refinery residual oil, and refinery off gases are available. In general, steam turbine applications are driven by balancing lower cost fuel or avoided disposal costs for a waste fuel, with the high capital cost and (usually high) annual capacity factor for the steam plant and the combined energy plant-process plant application. For these reasons, steam turbines are not normally direct competitors of gas turbines and reciprocating engines in distributed generation applications.

5.2.2.4 Microturbines

Microturbines are small electricity generators that burn clean gaseous and liquid fuels to create high-speed rotation that turns an electrical generator. Microturbines entered the field testing stage around 1997 and began initial commercial service in 2000. The size range for microturbines available and in development is from 30 to 350 kW. Microturbines run at very high speeds and, like larger gas turbines, can be used in power-only generation or in CHP systems. They are able to operate on a wide variety of fuels, including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines feature emissions rates that can be up to eight times lower than diesel generators.[3] In resource recovery applications, they burn waste gases that would otherwise be flared directly into the atmosphere.

Microturbines are ideally suited for distributed generation applications due to their flexibility in connection methods, ability to be stacked in parallel to serve larger loads, ability to provide stable and extremely reliable power, and low emissions. Types of applications include peak shaving and base load power (grid parallel); combined heat and power; stand-alone, back-up and standby power; ride-through connection; primary power with grid as backup; microgrid; and resource recovery. Target customers for most of these applications are found in the financial services, data processing, telecommunications, restaurant, lodging, retail, office building and other commercial sectors. Many of the early entry microturbines currently in service are in resource recovery applications where fuel costs are negligible and unattended operation is key.

5.2.2.5 Fuel Cells

Fuel cell systems, currently in the early stages of commercialization, differ fundamentally from traditional prime mover technologies. Fuel cells are similar to batteries in that both produce a direct current (DC) through an electrochemical process without direct combustion of a fuel source. However, whereas a battery delivers power from a finite amount of stored energy, fuel cells can operate indefinitely as long as the fuel source, hydrogen, is supplied. Two electrodes (a cathode and anode) pass charged ions through an electrolyte to generate electricity and heat. A

[3] "Grid Power Solutions: The North American Market for Distributed Generation and Ride Through Technologies." Venture Development Corporation, June 2001, p. 243.

catalyst enhances the process. Fuel cells have very low emissions profiles because the only combustion processes are the reforming of natural gas or other fuels to produce hydrogen and the burning of a low energy hydrogen exhaust stream that is used to provide heat to the fuel processor. Electrical generating efficiencies range from 3% to over 50% HHV.

Fuel cells offer the potential for clean, quiet, and very efficient power generation, benefits that have driven significant investment in their development in the past two decades. As with most new technologies, fuel cell systems face a number of formidable market entry issues resulting from product immaturity, over-engineered system complexities, and unproven product durability and reliability. These translate into high capital cost, lack of support infrastructure, and technical risk for early adopters. However, the many advantages of fuel cells suggest that they could well become the prime mover of choice for certain applications and products in the future.

Today, there are only two commercially available fuel cells for distributed generation applications, a 200 kW unit[4] that has been commercially offered since the mid-1990s and a 300 kW unit[5] just entering commercial introduction. Although nearly two dozen companies are currently field testing a variety of alternative fuel cell systems for market entry, the availability of a wide array of off-the-shelf, fully warranted fuel cell systems designed for broad customer classes is still some years away.

5.2.3 DG/CHP Owners and Operators

The main participants shaping the emerging DG/CHP market through pursuit of business interests include equipment manufacturers and packagers, distributors, consulting/specifying engineers, end-use energy customers, utilities, and ESCOs. The last three groups, as potential and current owners and operators of DG/CHP systems, are the investors whose decisions may be influenced by energy price volatility. Below, we characterize each of these groups and briefly state what benefits DG/CHP technologies might offer them.

5.2.3.1 End-Use Energy Customers

End-use customers are typically classified as residential, commercial, industrial, and institutional.

The *residential* sector comprises single family dwellings, townhouses, and in some contexts, multi-family residences, such as apartment buildings and condominium developments.[6] The prices residential customers pay for natural gas and electricity are regulated by state utility commissions. Utilities pass commodity costs through to these customers according to fixed formulas and schedules, while marketers supplying energy typically offer a fixed rate. Both utilities and marketers protect residential customers from the full impacts of price volatility because they assume the burden of managing volatility through mechanisms such as storage and hedging, as discussed in the previous volume. The degree of protection depends upon the

4 Offered by UTC Fuel Cells as the PC25.
5 Offered by Fuel Cell Energy as the DFC 300
6 For the purposes of this report, multi-family dwellings are considered part of the commercial sector.

portfolio of the supplier as well as the regulatory climate and other conditions under which they operate.

However, price spike effects, seasonal energy price variation, and variations in residential bills due to weather and consumption patterns, do impact residential customers at some level. Along with this, they are subject to outages, blackouts, voltage reductions, and loss of service due to adverse weather and distribution system events, all factors that suggest DG as a potential residential application.

In the *industrial* sector, which encompasses a variety of production, manufacturing, processing and assembly facilities, many energy customers are well along the path to managing their energy use and costs through commodity purchasing from marketers and the open market, on-site generation, hedging and other price risk management techniques, and use of alternative and back-up fuels. Energy-intensive industries such as steel, where fuel costs represent a significant portion of operating costs, continue to have strong incentives to consider DG/CHP along with other mechanisms for controlling and reducing costs. In fact, industrial customers such as paper and pulp mills, plastics thermoforming, and others with energy-intensive heat treating processes plus other uses for steam were among the first to adopt CHP systems. The availability of fuels, such as black liquor and wood waste, enhance the attractiveness for customers generating such by-products.

Many *institutional* energy users, like industrial facilities, find CHP an attractive application due to existing steam distribution systems and large thermal loads. Colleges and universities, prisons, hospital systems, and others are strong candidates for CHP systems, and many have been operating CHP systems for years.

The *commercial* sector is extremely varied, made up of about a dozen major subsectors including restaurants, office buildings, hospitals, supermarkets, and others. In some contexts, including this report, it also includes multi-family housing such as apartment buildings. While many commercial energy customers purchase both electricity and natural gas from their local distribution companies, others purchase the commodity from marketers and transportation services from the LDC. For example, one major national national full-service restaurant corporation operating four different restaurant chains supplies approximately half of its stores nationwide with natural gas through marketers, and about 25% of stores with electricity purchased from marketers. However, most are less sophisticated than industrial customers regarding energy, and have fewer options available to them for managing costs and price risks. There are as many different commercial customer tariffs as there are LDCs, with varying degrees of complexity. Commodity purchases through marketers are at negotiated rates, terms and conditions. Prices may be tied to prices at market hubs or a variety of other indices.

Commercial customer interest in DG/CHP has existed and is emerging for a number of reasons. If customers are relatively more concerned about electricity price stability than natural gas or alternative fuel stability, DG/CHP may appear attractive. Businesses that depend upon data processing and other electronic transactions, such as data centers, can suffer large losses when power quality fluctuations, interruptions and outages occur, even split-second disturbances. Current and anticipated problems with electricity transmission and distribution systems feed concerns about the quality and reliability of grid power. Electricity prices in some areas are high relative to natural gas price or alternative fuel prices, so significant energy savings can result from DG/CHP installations, particularly when thermal loads allow operation of CHP systems. Shaving electric usage at peak times can also result in large electricity cost savings.

5.2.3.2 ESCOs

ESCOs are businesses that develop, install, and finance projects designed to improve the energy efficiency and maintenance costs for facilities, typically over a seven to 10 year time period.[7] ESCOs began appearing in the late 1970s and early 1980s, following the steep increases in energy prices that occurred due to the oil embargo and other events of the decade. These increases set the stage for ESCOs to implement energy efficiency projects to help control customers' energy costs by reducing and managing energy use.

Acting as project developers, ESCOs typically:

- develop, design, and finance energy efficiency projects;
- install and maintain the energy efficient equipment involved;
- measure, monitor, and verify the project's energy savings; and
- assume the risk that the project will save the amount of energy guaranteed.

ESCOs in operation today include utility subsidiaries and affiliates, divisions of equipment or controls companies, such as Honeywell, and independent companies. The difference between ESCOs and other firms offering energy efficiency services, such as consulting firms and equipment contractors, is the ESCOs' use of performance-based contracting. An ESCO's compensation, and often the project financing as well, is linked directly to the amount of energy saved through the projects implemented. The cost of the services the ESCO performs are bundled into the project's cost and repaid through the dollar savings generated. Customers usually receive a guaranteed level of savings over their previous level of expenditures, with the ESCO earning its revenues on the difference between this level and its costs to provide the services to the customer.

As might be surmised from the discussion above, ESCO interest in DG/CHP technologies lies in the ability of these technologies to reduce customers' energy costs and provide a margin to the ESCO while doing so. Under a guaranteed savings arrangement, price volatility to the ESCO reduces the probability of achieving maximum margin, thus ESCOs are in the business of managing price volatility risk as well. The customer in this case has transferred considerations of price volatility to the ESCO.

To date, ESCOs have focused primarily on larger scale, CHP applications that provide electricity and steam or hot water to industrial, institutional or large commercial customers, with sales of excess electricity back to the grid in some cases.

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7 www.naesco.org.

5.2.3.3 Utilities

Natural gas utility interest promoting customer use of natural gas-fueled DG/CHP includes both the quantity and quality of the natural gas load represented. DG typically serves as a valley filler for the gas utility, consuming the most gas to supply air conditioning loads during the summer when gas use for space heating is at its lowest. While DG technologies can run on other fuels, natural gas is the favored fuel for environmental and other reasons. Utilities may own and operate DG/CHP systems through unregulated ESCO subsidiaries/affiliates, or encourage customer installations with PUC-approved incentives and special rates.

5.3 DG/CHP Investor Perceptions of Energy Price Volatility

5.3.1 Introduction

Are end-use customers attempting to incorporate the positives or negatives of energy price volatility into their consideration of DG/CHP technologies? What has the impact of price spikes been on customers who already have DG/CHP? What are the experience and perceptions of ESCOs, utilities and manufacturers in interacting with current and potential DG customers, and how does price volatility impact investor DG-related activities?

California, during the summer and winter of 2000, provides a worst-case scenario of price volatility for users of on-site generation who were not selling electricity into the grid. As detailed in the case study in Chapter 1, both electricity and natural gas prices became extremely unstable and spiked dramatically over a period of months. However, since most customers were insulated from the electricity price fluctuation due to rates that were frozen by legislative mandate, but more exposed on the natural gas side, DG units fueled by natural gas became uneconomic to operate, and most were shut down. While prices eventually settled back to more normal levels, the price spikes caused a large variation from the return on investment expected from DG/CHP installations.

Conversely, in the Pacific Northwest, a small industrial company recently installed 10 MW of natural gas-fueled DG under a special electricity rate schedule which was arrived at through a series of negotiations. The company had been devoting over one-third of its operating budget to electricity expenditures, paying rates more than double that of its competitors. The newly established schedule allows the company to purchase electricity on the open market or from third-party suppliers, and requires the electric LDC to purchase, at market prices, any and all excess electricity generated by the customer. With the appropriate electricity hedges in place, confidence in the stable functioning of natural gas markets, and an array of natural gas price risk management strategies available, the company considers its investment in DG as part of its portfolio of tools for minimizing energy costs and protecting against energy price fluctuations.

In the following section, we summarize the perceptions and activities of current and potential DG/CHP investors with respect to price volatility, based on our discussions with end-use customers, utilities, ESCOs and manufacturers, and on results from third party surveys.

5.3.2 Investor Perceptions - General

5.3.2.1 Expectations About Future Price Volatility

In a summer 2002 survey of 600 commercial and industrial end-use customers[8] conducted by Primen, three-quarters of respondents indicated they agree with the statement that natural gas prices are likely to remain volatile and unpredictable for the foreseeable future. More than 20% felt strongly about this. Overall, on a ten-point scale, the mean level of agreement was 6.7. Our discussions with individual customers mirrored this general perception.

On the electricity price side, individual customers with whom we spoke thought future volatility was likely. Some expected an eventual decrease in the overall level of electricity prices, while others are worried that overall levels will rise. Many customers observed that the natural gas market is much farther along the path to deregulation, with open and transparent processes and transactions that act to prevent manipulation of prices and to restore equilibrium when fluctuations do occur. These customers told us they believe that the electricity price spikes were caused by gaming of the system by electricity marketers that is enabled because of the immaturity, relative opacity and uneven development of deregulated electricity markets. Further deregulation is expected to bring prices down. California customers tended to attribute volatility to the state government's role in energy issues and frequent changes in policy.

ESCOs with whom we spoke made similar observations about the natural gas and electricity markets and the cause of the California electricity price spikes. They noted that their customers feel secure and comfortable with the financial products, storage and other means available to protect themselves from volatility on the natural gas side, but are worried about what will happen on the electric side. Among their customers, concern about volatility is embedded in anxiety about general price levels, with no differentiation unless the ESCO initiates a conversation about it.

One ESCO described "real" electric price volatility as stemming from transmission and distribution (T&D) and generation constraints, and expected future volatility to occur in T&D-constrained areas, as many generation markets are overbuilt. They also foresee the possibility of volatility caused by emotional reactions if terrorists strike the energy infrastructure. This company believes that energy companies will eventually leave participation in the commodity market to the trading arms of financial companies, a move that will help avoid price volatility.

5.3.2.2 Volatility Influences on DG/CHP Investment

The Primen survey results show a weak but statistically significant correlation between agreement about continuing gas price volatility and likelihood of purchasing a base load DG system in the next two years ($r=-.11$, $p<0.5$), where strong belief in continuing volatility

8 Respondents had average electric demand between 300 kW and 10 MW and fit into one or more of the following groups: industrial/commercial establishment with significant heat recovery potential; continuous process manufacturing; digital economy sector.

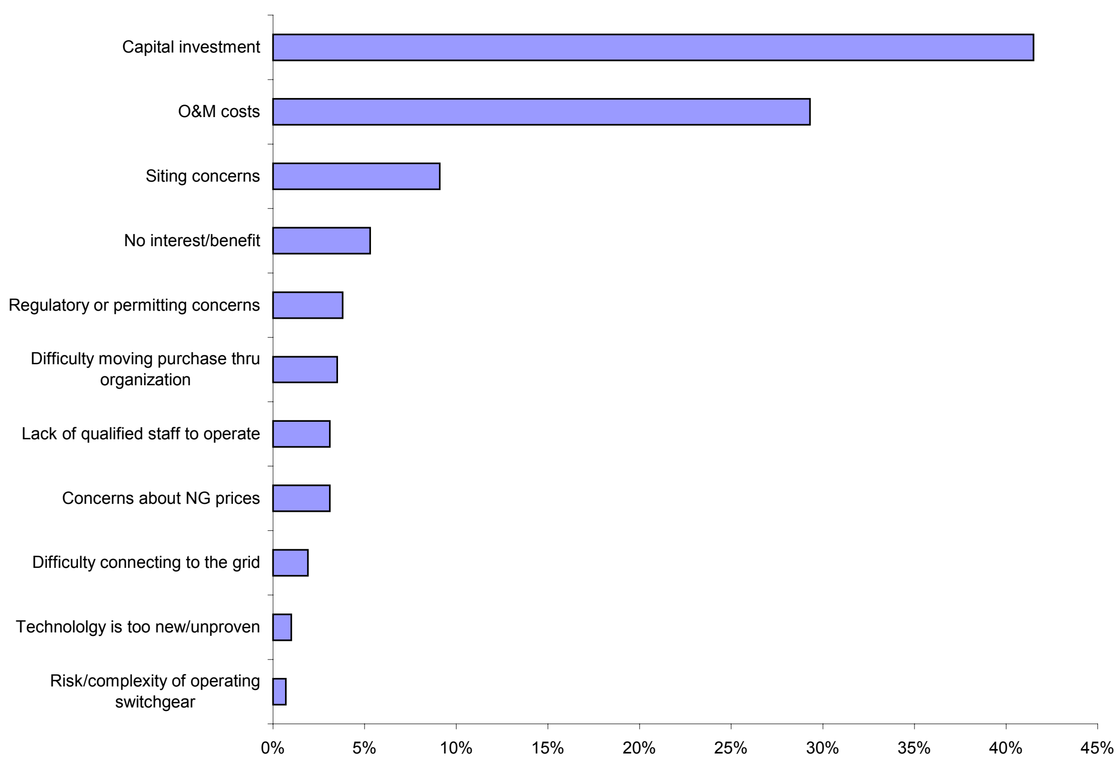
correlates with slightly lower estimates of DG purchase probability. This weak link disappears when customers estimate their probability of leasing a DG system.

When queried about potential barriers to acquiring a DG system for baseload use, only 3% of the respondents mentioned natural gas prices, as illustrated in Figure 5-1. As shown, the top three barriers cited were capital investment, operation and maintenance (O&M) costs, and siting concerns. Capital cost (including cost of up-front installation engineering) as a major barrier to customer DG investments surfaced throughout our conversations with customers, ESCOs, utilities and manufacturers.

The Primen survey respondents did not mention price volatility as a barrier to DG/CHP projects at all. However, since fuel costs are a major component of O&M costs, the barrier presented by O&M costs encompasses at least the overall level of natural gas prices. Thus, when viewing price volatility concern as uncertainty about the overall level of future prices, the survey findings do point to volatility as a barrier to customers' direct investment in baseload DG systems.

Figure 5-1

Percent of Respondents Citing Specific Barriers to Baseload DG



Primen's follow-up conversations with individual customers provided conflicting support for this conclusion. Among the 20 customers strongly considering acquiring a baseload DG system, only one mentioned natural gas price concerns, stating that these concerns had slowed the company's adoption of DG. Another customer stated that fuel price volatility had actually increased their company's interest in base load DG, as they are a firm that deals in commodity markets as part of their core business and views this as one of their strengths.

Our conversations with individual companies and ESCOs revealed more insights into these two approaches. On the one hand, customers stated that increased price volatility reduces the likelihood they will invest in capital-intensive energy equipment such as DG, or increases the performance they demand from energy projects. On the other hand are customers whose business circumstances and ability to buy energy on the open market or from marketers leads them to view DG/CHP as a tool tied to others in a portfolio of energy management strategies. Examples in the sections that follow highlight these two facets of the issue, along with others.

5.3.3 Commercial Customers

5.3.3.1 Context of Decision Making

In each commercial sector, there are drivers of profitability upon which management focuses its operational interests. Examples of such drivers are food quality and labor productivity in the restaurant industry; guest comfort in the lodging industry; and store dwell time in the retail industry. To the extent that DG/CHP can improve these drivers, there is special interest in the technologies. However, there is not a wide, deep or uniform base of knowledge or experience with DG/CHP technologies in most segments of the commercial market. Ownership, compensation structures, decision making processes and other factors all influence how profitability is achieved and maintained. These factors also influence energy equipment decisions, including DG/CHP.

In most commercial facilities, energy expenditures are not the largest budget item, or even the second, third or fourth largest, hence do not receive the same level of attention as major budget components such as labor. However, in sectors with very small operating margins such as supermarkets, energy cost changes can quickly tip the profitability scale one way or another. Additionally, many commercial establishments do not employ internal engineering or maintenance staff with understanding of onsite power generation technologies. It is within these contexts that most commercial customers make DG/CHP decisions.

There is wide variation in the level of energy sophistication among commercial customers. National account customers – those with facilities in more than a handful of states – tend to be more savvy than single-site or smaller chain companies. Many who have not felt the effects of price spikes or who have a lower energy sophistication level do not differentiate price volatility from the overall level of energy prices. Meanwhile, more sophisticated companies not only understand price volatility within each fuel market, but are purchasing energy commodity from marketers and managing their own energy portfolios, including price volatility protections.

5.3.3.2 Example: National Restaurant Company

A restaurant company operating four different quick service restaurant concepts has a total of over 1,200 stores nationwide, with $4.4 billion in food sales. While all stores are company-owned, each brand operates independently, so decisions regarding energy equipment are made separately by each brand's management. Energy expenses amount to 3 to 4.5% of the operating budget of a typical restaurant. The company had established an energy services department within the corporate engineering division in the early 1990s to seek out opportunities to achieve energy savings. The department evaluated and convinced concept managers to implement a number of quick-payback, one-time energy efficiency measures, such as switching to high-efficiency lighting and programmable thermostats. However, with the loss of the department leader, the department was transferred to purchasing and eventually disbanded.

The energy services department had investigated DG/CHP as a way to enhance energy efficiency and reduce energy expenditures, but felt it could not recommend the technology because concept management would not accept it. Reasons for this were:

- Payback period too long. Paybacks of less than one year for capital investments are required, a standard followed throughout the restaurant industry. The up-front cost was a particular issue, related in part to the maintenance concerns explained below.
- Maintenance/capital cost concerns. The company's incentive structure provides bonuses for managers based on store profitability. Expenditures on equipment maintenance directly reduce the base for bonuses, while capital expenditures for replacement equipment do not. Hence, equipment maintenance occurs infrequently and equipment is "run into the ground." In this case, the up-front cost to the corporation to replace DG equipment would be prohibitive.

The energy services department's move to purchasing reflects the choice made by this company to manage energy costs and volatility via commodity purchasing. Fully 50% of the company's restaurant locations buy natural gas from a marketer, and 25% purchase electricity from a marketer. Energy purchasing and contracting is handled centrally. The company also hedges its purchases.

Regardless of price volatility developments, DG is not likely to be re-evaluated by this company any time in the near future.

5.3.3.3 Example: National Hotel Company

Some commercial customers with larger facilities, such as resort/hotel management companies, express a high level of interest in the concept of an ESCO installing, operating and maintaining DG/CHP units for them, selling electricity to them at guaranteed prices lower than their current rates, and perhaps providing hot water or steam as well. Part of their interest lies in controlling energy costs, including exposure to price volatility. In the depressed travel scenario of the post-9/11 era, hoteliers feel they cannot raise rates to reimburse themselves for higher than planned for energy costs, and thus wish to ensure as much stability in the future as possible.

For example, a hotel company that owns and manages branded upscale hotel and resort properties worldwide has been analyzing DG/CHP for the last few years, tracking new product introductions and visiting installation sites. The average peak load of their properties is 1 MW. Most properties have a diesel generator set to provide emergency backup in case of outages. However, for noise, aesthetic and environmental reasons, their technologies of choice for baseload on-site generation are microturbines and fuel cells.

The company sees peak shaving as a potential application that will probably become more important in the future, but to be worthwhile, 300 to 400 kW would need to be shaved. A microturbine of this size has yet to be made commercially available, and while it is technically possible to operate a bank of multiple units, their analysis shows that cost per kW of capacity with such an arrangement is uneconomic. If a DG unit could operate both as emergency backup and peakshaver, it would be viewed as an emergency generator that pays for itself, and would be attractive to them. They have installed a fuel cell and a microturbine on a trial basis and are carefully monitoring results.

This customer seeks energy savings, protection from price spikes, ability to operate during power outages, and enhanced savings via use of waste heat. Like customers in other sectors, they view energy issues as tangential to their core business. Energy projects compete with much more visible capital projects, such as sleeping room refurbishment, grounds improvement, and addition of guest amenities such as spas. The company would welcome discussions with an ESCO willing to install, own and operate DG/CHP and provide a guaranteed level of savings over their current tariffs. This would free them to focus just on controlling their energy consumption through conservation and efficiency measures.

5.3.4 Industrial Customers

5.3.4.1 Context of Decision Making

As mentioned previously, energy expenses represent a significant portion of the operating expenses of many industrial firms. Energy supplies a wide variety of manufacturing, heat treating, drying, melting and other processes, some of which are very energy intensive. Many facilities' thermal loads make CHP an attractive option, as does the production on-site of by-product fuels. Because of the impact on their operations, companies in the industrial sector have long been proactive in seeking out ways to reduce energy costs, including buying energy from marketers and the open market, installing CHP systems, and seeking to bypass the distribution systems of local utilities to avoid LDC transportation charges and access cheaper gas supplied by a pipeline company, independent power producer or energy marketer.

Unlike many commercial customers, industrial facilities often employ engineering and maintenance staff, including specialists such as steam engineers, who are familiar with DG/CHP and other advanced direct-fired and thermally-driven equipment. They are also not subject to the spectrum of demands likely to face commercial concerns, such as noise, customer comfort, and aesthetics that may reduce the feasibility of some DG/CHP technologies. On the other hand, environmental regulations may restrict their choices.

The following examples describe the contexts in which several different industrial customers have operated and the role price volatility has played, and is playing, in their DG/CHP decision-making.

5.3.4.2 Example: Single Facility Small Industrial Customer

A cold storage company with processing facilities and over 1 million square feet of cold storage capacity faced electricity costs more than double those of its competitors in the early 1990s. Electricity costs comprised one-third of its operating expenses. Seeking a lower rate that would allow it to become more competitive, the company embarked on negotiations with the electric LDC that stretched over three years. With no special rate in sight, the company opened discussions with a municipal utility district (MUD) and the federal agency supplying power in a neighboring state. These discussions resulted in plans to construct a high-voltage transmission line to bypass the LDC and serve both the company's 10 MW load and the larger load of a neighboring industrial plant.

To avoid this loss of load, the LDC obtained the PUC permission needed to offer the two companies a special rate. This rate was set as the market price determined at the nearest interstate transmission border. The arrangement lasted for another three years, but eventually proved unsatisfactory to the company when the LDC altered the way the rate was computed. As the company began to revisit the bypass plans, the electricity crisis of summer 2000 hit. The company, faced with the prospect of being forced to shut down due to sky-high electricity bills, convinced the state government to intercede. Short-term arrangements to run a turbine plant extra hours were made, and the company opted to enter into a series of three one-month hedges that lowered its costs.

As cold weather settled in, the LDC began experiencing difficulties, as it is a winter-peaking utility that purchases electricity on the open market to meet winter peaks. A new special tariff available to industrial customers was quickly created. Under the tariff terms, customers can buy electricity from the open market and third-party suppliers, and then receive transportation services from the LDC at set rates. Key to this discussion, the tariff also encouraged on-site generation by requiring the LDC to buy, at market prices, all excess electricity generated by the customer.

At the same time that the company began utilizing long-term electricity price hedges, it began evaluating DG options. Some months later, it installed 10 MW of engine-driven, natural gas-fueled on-site generation. The nine engines, each slightly over 1 MW of capacity, are able to follow closely the very spiky load of the facility, and operate efficiently at part-load. The company purchases gas on a short-term basis, as it does not know in advance how much it will need on any given day, week or month. The company quickly established the algorithms that determine when and for how long the engines operate, how much internal load is met, and how much electricity is generated for sale to the LDC.

In the example, price volatility, in the sense of both overall price levels and price spike events, were the main drivers of this company's decision to install and operate DG.

5.3.4.3 Example: National Printing Plant Company

A printing company with 26 plants across the U.S., all of which operate on a 7x24 basis, budgets about $80 million per year for energy. Two-thirds of this is for electricity and one-third for natural gas. In many parts of the country, they are able to purchase energy on the open market, employing price risk management tools to minimize exposure. However, in some locations, services remain bundled and utilities “won’t even negotiate.” In the early 1990s, they installed a 3 MW gas turbine-based CHP system in a California plant, a decision driven primarily by energy cost savings considerations and encouraged with incentives from the gas LDC. This plant has enabled continuing (albeit partial) operation of the plant during the blackouts that have occurred in the state.

Despite the fact that the CHP system sat idle during the natural gas price fly-up of January 2001, the company is considering installation of CHP at the rest of their facilities. The increased volatility tends to cause them to demand more performance from capital-intensive energy investments. Their outlook on natural gas prices is that they will vary with the level of overall demand created by rises and fall in the GDP. They anticipate that further deregulation will improve the energy cost situation, attributing the problems in California to illegal price manipulation by power producers. In their experience, liquidity in the energy markets is improving.

Many ESCOs have approached this company over the years, but the uniqueness of their manufacturing operations tends to diminish the effectiveness of the ESCO model. The few attempts they have made to work with an ESCO have been disappointing. In particular, they have found that ESCOs are not well equipped to work successfully with environmental regulations.

For this company, with its capabilities and expertise in open market commodity purchasing and risk management techniques, price volatility has had little negative or positive impact on the on-site generation decision.

5.3.5 ESCOs

5.3.5.1 Context of Decision Making

The number of ESCOs who install, own and operate DG/CHP projects are limited, and most of these have focused on targeted institutional, industrial and large commercial customers. The following two examples illustrate how these ESCOs are addressing customer needs with DG/CHP and the role of price volatility in their activities.

5.3.5.2 Example: Institutional Customer

In the early 1990s, a county hospital in the Southwest faced electric rates that featured a high demand charge component with a series of steep ratchets. The hospital had drawn up a plan for expansion of its existing facilities and construction of a new psychiatric center, and there were several university buildings on the campus to be served. Lacking the space needed to expand the existing 25-year-old distributed boiler and chiller facilities, the hospital retained an ESCO to develop a central plant concept. The ESCO recommended installation of a CHP plant featuring three natural gas-fueled reciprocating engines, two steam-driven absorption chillers and two natural gas-fueled engine-driven single effect chillers. Exhaust and jacket heat recovered from the reciprocating engines, along with exhaust heat from the engine-driven chillers, generates steam in a heat recovery steam generator. The steam feeds into one large header that distributes the steam to individual air handling units and to heat exchangers for the production of hot or chilled water.

The hospital funded the equipment purchase and the ESCO installed and operated this system for a number of years. Several years ago, the hospital implemented the recommendation of an outside consultant to bring plant operation in-house, as part of a strategy to improve cash flow and profitability. During the gas price spikes of 2001, the plant was left operational, because if the hospital purchased electricity from the grid, the demand charge would ratchet up to a new, much higher level.

For this customer, the main drivers for installation of CHP were high electric demand charges, the need to serve a significantly expanded future load, and significant thermal loads. Due to the structure of the electric demand charges, the CHP plant has remained economic to operate even during gas price fly-ups.

5.3.5.3 Example: Retail Customer

A national ESCO recently entered into an agreement with a national big box retail customer to install, own and operate CHP systems in stores around the country, beginning with stores in the region with the highest electric rates. The customer's objective is to reduce and achieve stability in its energy expenditures. Initially, the ESCO planned to install a natural gas-fueled mini-combined cycle unit in each store that used the waste heat from the primary generator to produce additional electricity in a secondary generator. However, with the technology development schedule lagging, the ESCO has chosen instead to utilize the waste heat from the engine generator in a liquid desiccant system. The desiccant system works with the rooftop heating/cooling units that the customer already uses, drying air before it is cooled. The waste heat from the generator heats the lithium solution that has absorbed moisture from the air, separating the lithium and water molecules and thus regenerating the desiccant solution.

The ESCO, which is doing its own natural gas purchasing to supply the CHP units, feels comfortable and confident with the natural gas market and the mechanisms available for managing price risk, and this adds to their expectation of earning a profit on this contract. The customer in this case has now assured itself of a set amount of power supplied at a rate that guarantees savings over their current situation, and moved some price volatility risk onto the ESCO.

5.3.6 Residential Customers

There has been little chance to analyze the impacts of price volatility on residential customer DG decisions, as there are no products specifically designed for residential use and thus few residential DG installations to date. However, focus group work completed in 2000 sheds some light on how these customers might approach DG decisions. Primen conducted a series of six focus groups with natural gas customers in Chicago, San Diego and Washington, D.C. The participants were affluent, custom single family homeowners, with either a home business or lots of high tech features and appliances in their home. These consumers were considered most likely to be early adopters of new energy technologies. The purpose of the focus groups was to gauge the value of potential fuel cell product attributes in terms of both cost and non-cost factors, and to assess the implications for market introduction.

Participants wanted a proven product that would satisfy what they consider to be a basic need. Volatile energy prices were not a motivator for purchase. Even in San Diego, which was experiencing electricity price spikes at the time of the focus group, the protection that a fuel cell could offer was almost a non-factor for these consumers.[9] Some participants did, however, make reference to shifts in relative fuel prices, and said that if they installed a fuel cell, they would remain connected to the grid and would monitor fuel prices so they could switch back and forth to get the best deal.

Focus group participants as a whole viewed a fuel cell as an exact substitute for electricity purchased from the grid, and did not value the additional point or two of reliability they felt it represented over grid power. Consumers in areas with outage problems found the fuel cell concept attractive as a back-up power source, not a baseload power generator. However, outage costs were not viewed as significant, and power quality fluctuations described as just a nuisance.

5.3.7 Summary and Conclusions

Many of the current and potential investors in DG/CHP that are the subject of this chapter – end-use energy customers and ESCOs – have observed or experienced first-hand fluctuating natural gas and electricity prices. Our discussions with customers, ESCOs, utilities and manufacturers, along with our review and analysis of third-party customer research, suggest the following general and specific conclusions about price volatility impacts on DG/CHP investment decisions.

- <u>Smaller commercial customers: Little impact.</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 in their thinking. 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 O&M, and internal decision making processes and criteria are likely to discourage investment in DG/CHP without price volatility having ever entered

[9] Electricity prices in CA had quadrupled at this point.

the picture.

- Commercial/small industrial customers: May slow down DG/CHP decision or cause them to consider an ESCO partner.
  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 is driven mainly by opportunity cost of outages and quality disturbances and 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.

- Industrial customers: May encourage DG/CHP, depending on other factors.
  With significant thermal loads, dual- and alternate-fuel capabilities, and CHP an established technology among this group, CHP is often considered attractive without thought for price volatility. Many such customers 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.

  In spite of natural gas price spike events, industrial customers expressed trust and confidence in the stability of natural gas markets, citing the maturity and openness of deregulated natural gas markets and the many tools available for price risk protection. Conversely, they saw less stability on the electric side, as the immature market is filled with loopholes that allow gaming of prices to take place. In addition, these customers are used to natural gas choices and are frustrated about the relative lack of options on the electric side for reducing costs and managing volatility. This serves as a motivator for installing DG/CHP.

- Residential Customers: No impact expected.
  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 price volatility in the electricity and

natural gas markets will not significantly influence residential homeowner decisions about future DG product offerings either positively or negatively.

- ESCOs: May encourage DG/CHP investment.
  Like industrial energy customers, ESCOs appear comfortable with the stability of natural gas markets and the tools available to them to manage natural gas price volatility on behalf of their customers. 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 use waste heat to help reduce electric cooling loads.

5.4
Economics of DG/CHP Investments

5.4.1 Introduction

The economic costs and benefits of DG/CHP equipment are the primary considerations for potential investors analyzing these types of systems. This section describes the economic and financial aspects of DG and CHP. As mentioned previously, this analysis looks at two types of investors: an end-use customer owner/operator and an ESCO. To assess the attractiveness of a DG or CHP investment, prospective investors perform cash flow and life cycle cost assessments. The resulting estimates of the investment's net present value, simple payback, return on equity, and return on investment are normally used to gauge the soundness of the investment.

5.4.2 Economic Benefits of DG and CHP

5.4.2.1 Energy Cost and Other Savings

A commercial or industrial end-use energy customer who plans to own and operate the DG or CHP investment characterizes the owner/operator scenario. In this case, the economic benefit of the DG system is the savings from avoided electricity purchases and, in the case of CHP, the avoided cost of thermal energy. Peaking and standby units can achieve greater savings by avoiding peaking demand charges and high time-of-use rates, or by receiving payments from an electric system for load reduction during peak demand periods. In CHP systems, the thermal requirement is baseloaded and any extra electricity generated is sold to the grid. Thus, another potential benefit with CHP is the revenue from sales of electricity generated.

In premium power cases, a DG or CHP investment provides the power quality and reliability that an industrial or commercial owner requires. The benefits of installing a DG or CHP technology in the premium market go beyond the usual energy-related cost savings. A company in the premium power market may incur huge financial losses if a power failure occurs, through lost production time, ruined product, and disabled equipment. Thus, in this market, there is a substantial credit, albeit difficult to quantify, placed upon the power quality and power reliability provided by the investment.

Industrial and commercial firms might not want to incur the responsibility of owning and operating DG/CHP equipment when doing so is not a part of their set of core competencies. In these cases, ESCOs may be willing to install, own and operate the equipment, providing the industrial or commercial firm with its energy requirements by selling electricity or both electricity and steam to them. The benefit to the ESCO is the profit from the sale of electricity and steam to the end-use customer as they are procuring fuel at lower rates from suppliers.

5.4.2.2 Electricity Prices

The primary benefit of a DG or CHP investment is the savings from avoided electricity purchases. The amount of savings differs by customer type and by state, since electricity rates differ by customer type and state. Electric power industry restructuring has further compounded the differences. In a regulated environment, electricity prices (wholesale and retail) were based on the utility's embedded costs plus a negotiated rate of return. With the advent of electric industry restructuring, wholesale prices have changed dramatically. Wholesale transactions are now allowed to be structured using market-based rates. At the retail level, a handful of states (Pennsylvania, California, Massachusetts, Oregon and Washington) have opened the market to include alternative providers.

Large commercial and industrial end-use customers tend to enjoy lower electricity rates than other, smaller customers. Because of the size and characteristics of their loads, utilities and other power suppliers offer lower rates. These customers are also offered alternative rate designs, including interruptible service and time-of-use rates.

5.4.3 Costs of DG and CHP

There are three different types of costs that are considered when a potential investor analyzes a DG or CHP equipment investment:

- capital equipment, installation costs, and financing costs;
- fuel costs;
- non-fuel O&M costs.

For a more appropriate accounting of costs, investors apply after-tax analysis. After-tax analysis takes into consideration tax-related items such as capital depreciation and business expense deductions that impact investment cash flows. Including depreciation, for example, tends to reduce the impact of capital cost on investment cash flow, and thus has the effect of reducing the value furnished by lower project capital costs, though this remains one of the most significant technology factors affecting CHP investment economics.

There are other costs that could and do occur when investing in a DG or CHP system. Add-on pollution control equipment is required for certain equipment in certain sites and regions. Utilities typically impose substantial system exit fees, competitive transition charges, and interconnection costs, and apply special back-up and standby power rates. These charges and fees have discouraged, and will continue to discourage, many would-be DG/CHP investors.

5.4.3.1 Natural Gas Prices

Fuel costs can account for as much as 80% of the total cost of generating electricity in a DG system, depending on the technology. Thus, current and future fuel costs are a major consideration in the economic assessment of a DG or CHP investment. However, natural gas end-use prices can differ substantially by customer type, load size and shape, and state. Small commercial customers generally purchase natural gas from a local distribution company (LDC). LDC charges and rates to these customers are subject to regulatory review, and generally reflect the rolled-in average cost of natural gas to the LDC Citygate, plus the LDC distribution (transportation) charge. These customers face gas prices that do not vary with short-term (day-to-day or week-to-week) changes in energy market prices. Nevertheless, more persistent price changes, such as the winter-long increase in natural gas prices that occurred during the 2000-2001 winter, do result in substantial price increases for a period of time.

Most large commercial and industrial customers rely on the LDC only for gas transportation services. They purchase natural gas either at market prices or through a natural gas marketer who provides hedged supply. In both cases, these customers react to market prices. If the customer does not have any hedged supply, the customer will be purchasing at market prices.

5.4.4 Economic Benefits

This section illustrates the economic benefits of a DG or CHP investment. In the first example, we provide an economic analysis from the perspective of an industrial owner/operator investing in a CHP system. The second example presents an economic analysis of an ESCO investment in a CHP system.

To estimate the economic benefits of an investment, a net present value (NPV) analysis based on nominal dollars is performed. For all of the analyses done for this study, we made the following assumptions:

Nominal discount rate	6%
Income Tax – Federal	35%
Income Tax – State	8%
Inflation Rate	3%
Debt/Equity Ratio	80/20
Loan Interest Rate	7%
Term of Loan	15 years

5.4.4.1 End-Use Customer Owner/Operator

In this example, an industrial customer will operate a 5 MW CHP system as a baseload thermal unit. The customer satisfies their thermal requirements first, purchasing any additional electricity needed from the grid, or selling any excess electricity generated back to the grid. The industrial customer is assumed to be operating a gas boiler to meet current thermal energy needs and purchasing electricity from a utility.

Table 5-2 presents the technology cost and performance data for a 5 MW advanced reciprocating engine system (ARES) technology. The life cycle cost analysis uses national electricity and natural gas price projections from the U.S. Energy Information Administration (EIA). The price at which the customer can sell electricity to the grid (buy-back price) is estimated by reducing the average electricity price by 20%. An industrial customer with this type of CHP facility achieves cost savings from electricity and thermal energy produced by the CHP unit.

Table 5-2
Technology Cost and Performance Data
(5MW ARES CHP Unit)

	Capital ($/kW)	Non-Fuel O&M ($/kWh)	Power to Heat Ratio	Electrical Heat Rate (HHV Btu/kWh)
5 MW ARES Industrial Combined Heat and Power Generator	1,268	0.0107	0.91	7,817

Table 5-3 presents the results of the economic analysis of the ARES technology using the EIA energy price forecasts. The results show that the owner/operator's investment will generate a net present value of over $8 million, with a payback of less than five years.

Table 5-3
Economic Assessment Results – Industrial End-Use Customer

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)		
Base Case	6,341,860	8,205,725	5		

5.4.4.2 Energy Services Company

In this example, an ESCO will invest in a 5 MW ARES technology, sell thermal energy and electricity to an existing industrial customer at a 10 percent discount, and sell any extra electricity generated to the grid. The industrial customer is assumed to be operating a gas boiler to meet their current thermal needs, and purchasing electricity from a utility. For the life cycle cost analysis, we use EIA's national electricity and natural gas price projections. The buy-back electricity price is estimated by reducing the average electricity price by 20%. Table 5-2 presents the technology cost and performance data for a 5 MW ARES technology.

In this scenario, the industrial customer's savings will come from the discount that the ESCO's price represents over the prices they currently pay. The ESCO's revenues will come from the steam and electricity sales to the industrial customer and from the sales of the residual electricity to the grid. Table 5-4 presents the ESCO's net present value and payback of the investment. Over a 20-year period, the net present value is $3.8 million dollars. Payback is expected at six years.

Table 5-4
Economic Assessment Results - ESCO

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)		
Base Case	6,341,860	3,800,242	6		

5.4.5 Market Barriers to DG and CHP

Investors in DG and CHP systems must contend with a variety of market barriers, including environmental and siting/zoning regulations, utility resistance, power industry restructuring, and customer concerns. These are discussed below.

5.4.5.1 Electric Industry Restructuring

The restructuring of the U.S. electricity industry has provided the main impetus for interest in DG and CHP technologies. Nevertheless, it has also created some major barriers, including expensive electric utility system exit fees and competitive transition charges (CTCs) that help utilities recover stranded costs. Also, there are still numerous unresolved issues on the handling of DG and CHP systems by the independent systems operator (ISO) and regional transmission organization (RTO), including access, jurisdiction, and technical requirements. Until these are resolved, uncertainties regarding DG systems within the ISO/RTO system will remain.

5.4.5.2 Environmental Regulations

Environmental permitting can be a major barrier for any DG or CHP installation. In some states, small power producers (such as a DG/CHP user) are subject to the same requirements as large power producers (e.g., independent power producers). In this case, meeting the requirements can prove to be an expensive endeavor for the small DG/CHP user. In some cases, the efficiency of cogeneration installations used as a permitting criterion is determined based on combustion efficiency only, rather than overall efficiency, a calculation that disregards the efficiency gained from the thermal energy production and use and disadvantages the installation in the environmental arena.

5.4.5.3 Zoning and Siting Restrictions

Local zoning policies, building codes and standards, and other issues can affect the installation of DG and CHP systems. Communities may impose noise, aesthetics, and land use restrictions that complicate DG and CHP projects. Fire codes and other building code requirements (specifically, fuel storage and supply) may hinder certain DG and CHP technologies from penetrating some markets.

5.4.5.4 Utility Policies

Electric utilities can and do pose major barriers to DG and CHP investments. As mentioned above, they typically charge DG and CHP customers expensive back-up and standby power rates, high interconnection costs, large exit fees and competitive transition charges. A substantial number of DG and CHP projects have not been fully realized because of these costs. Utilities have also performed selective rate discounting to encourage customers intending to install DG or CHP technologies to cancel their projects. Finally, net metering issues may be difficult to resolve, such as valuing the customer's credit for generating its own electricity and the excess electricity sold into the grid.

Apart from high interconnection fees, utilities have imposed other barriers related to interconnection requirements. Some utilities remain reluctant to accept safety and protection devices built into a DG or CHP system, requiring more expensive but unnecessary equipment. Utilities may also require that their own staff test the DG or CHP equipment even when they do not have expertise to do so correctly or to interpret the results appropriately. Frequently, utilities also require that a DG or CHP customer perform ”pre-interconnection” studies. These expensive and time-consuming studies impose additional financial and time burdens on potential investors.

5.4.5.5 Customer Perceptions

End-use customer and ESCO awareness and attitudes about DG/CHP systems vary widely, from almost complete lack of knowledge about the technologies and their capabilities to sophisticated tracking of rates and of new DG/CHP product development. Many customers regard grid-supplied electricity as highly reliable and electricity-fueled equipment as cheaper up front, easier to maintain, and certainly much more familiar than DG/CHP technologies. Operating and maintaining advanced energy equipment does not fall within the bounds of most companies' core competencies, leaving them hesitant and unsure who to trust when it comes to considering DG/CHP systems, and unprepared to run the equipment. Finally, in most sectors, there are competing uses for capital that receive much higher priority, particularly for projects that are visible or otherwise tangible to their own customers.

5.5
Energy Price Volatility in DG and CHP Markets

5.5.1 Introduction

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

Energy price volatility creates uncertainty and concern in the minds of consumers and producers, who may delay decisions to purchase appliances and equipment or make investments in new technologies. Such delays may result in lost market opportunities and inefficient long-run resource allocations.

This section focuses on the impact of energy price volatility on the DG and CHP markets. It examines the way an investor might try to address the risks associated with uncertain and volatile prices. Section six will present a quantitative assessment of the impact of volatility on the investor's payback and investment return.

5.5.2 Sources of Volatility

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 in both the short-term and the long-term.

- In the short-term, weather affects to a large degree the demand for natural gas and electricity. Because weather conditions can change rapidly and unexpectedly, large and sudden shifts in "service demand" can occur that create imbalances that must be relieved.
- In the longer-term, prices signal the need to develop new resources, and provide the incentive necessary in a free market to prompt investment in new resources.

Demand price response differs depending on energy price levels relative to other energy sources. 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. 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.

Recent years have also produced periods of highly volatile electricity prices. These events were usually caused by unusual weather patterns and limited generating capacity. Furthermore, electricity suppliers rely more heavily on natural gas, especially to supply marginal generators. Thus, during periods of high electricity demand, more and more units demand more natural gas, producing price spikes for both electricity and natural gas. Thus, a DG or CHP user or investor will have to contend with both electricity and natural gas price volatility.

5.5.3 Risks and Hedging Mechanisms

There are a variety of ways to hedge or reduce the risks associated with volatile prices. An investment in a dual-fuel system instead of a single-fuel system can minimize the impact of unpredictable prices. Combustion turbines and microturbines can operate on natural gas or alternate liquid fuels, such as diesel, so during periods of high natural gas prices, the turbines can operate with the alternative fuel. However, environmental and other equipment performance characteristics under alternate fuel operation can be worse, restricting the amount of time that the equipment can run this way. Boilers supplying steam turbines can be configured to operate on several alternative fuels, with a wide spectrum of fuels possible. Reciprocating engines must be dedicated to a single fuel, so do not provide the dual-fuel system switching advantage. While fuel cells can operate on reformed natural gas, methanol, landfill gas, and other sources of hydrogen, a different reformer is required to process different fuels. For larger DG or CHP investors, investments on various systems with different fuel sources can also minimize fuel price risks.

Another way to hedge risk is to engage in the various financial instruments offered by the market. These include futures contracts, price swaps, options, and forward contracts, all with attendant advantages and disadvantages. Using such instruments requires market intelligence and expertise. For a small DG or CHP investor or for an owner/operator firm whose core competencies do not encompass this type of intelligence or expertise, the need to engage with these financial instruments could easily discourage investment. An ESCO, on the other hand, if it is already in the business of commodity acquisition, would have this type of expertise as part of its core competencies, and thus is expected to engage in these financial instruments.

In the case of a small DG or CHP investor or a firm that does not have core competency in futures instruments, the investor can either secure long-term gas and electricity contracts or a contract with an ESCO to operate its energy system, as described in Chapter 4. This will insulate their operations from the volatile movements of gas and energy prices.

Finally, a DG or CHP plant may itself represent a physical hedge against volatile electricity prices, especially when operated as part of a portfolio of energy management strategies, as illustrated in Chapter 4.

5.5.4 Impacts of Energy Price Volatility

Two of the fastest growing markets for natural gas are DG and CHP. As discussed, potential investors in these markets encounter numerous barriers, including interconnection requirements, environmental permitting, zoning and siting restrictions, expensive back-up/standby power rates, high interconnection costs, exit fees and transition charges. Highly volatile energy prices further complicate the situation. As natural gas and electricity price volatility are interrelated, DG and CHP investors must contend with a variety of volatility scenarios. The volatility that the energy market has exhibited in the recent past and may be expected to show in the future could be perceived as increased project risk, rendering financing for DG and CHP projects more difficult to obtain.

Because natural gas costs account for the largest portion of the total cost of generating electricity with a DG system, natural gas price volatility can unduly affect the viability of running a DG or CHP system. While gas price volatility alone does not immediately imply critical risk, when a volatile input price (e.g., natural gas price) is combined with a stable or fixed output price (e.g., electricity price), a firm can face serious uncertainty in its financial operations. In another instance, power generators can wind up in a riskier position if they sell in a market that is competitive and dominated by generation from another fuel source. If their fuel costs increase more than the fuel costs of other types of generation, then it is likely that electricity price (in the spot market) will not completely cover their increased fuel prices, resulting in financial losses.

The primary alternative to DG is the centrally-generated electricity. Thus, the effects of gas and electricity price volatility on a DG user relative to its effects on a central utility are an important consideration when assessing the value of a DG project. In general, the central utility can generate electricity at a higher fuel efficiency rate than a power-only DG user. This means that the central utility experiences lower fuel costs per unit of electricity generated. Also, a central utility has a portfolio of generators (fueled by coal, uranium, residual fuel oil, or renewable energy), and thus may have the option of switching to other fuel generators when gas prices become too high. Thus, relatively, the central utility will be less impacted by volatile natural gas prices than a DG user.

Customers with large thermal loads that have traditionally used CHP systems, such as the paper, petroleum refining, and chemicals industries, and institutional customers such as hospitals and universities, will continue to install and operate CHP equipment, despite volatile gas prices. The savings from cogeneration are substantial enough to warrant the risk posed by volatile prices, which these customers manage by procuring long-term contracts or establishing power-marketing subsidiaries to hedge their risks. Industries that rely in part or whole on byproduct fuels such as wood waste have correspondingly less concern about natural gas prices.

Commercial and industrial firms requiring premium power (including data centers, financial institutions, computer and electronic manufacturers) will continue to consider DG or CHP systems, as financial losses could be substantial in the event of power quality events such as voltage reductions, and reliability events such as outages. These investors will hedge their risk with long-term contracts, or may be able to incorporate all or a portion of the energy price changes into their product prices.

5.6 Quantitative Analysis

5.6.1 Introduction

This section presents the results of a quantitative analysis examining the impact of energy price volatility on DG and CHP investments. Based on the cash flow analysis for an owner/operator scenario and an ESCO scenario discussed in Section 5.4, we ran several risk scenarios incorporating volatility in natural gas prices, electricity prices and in electricity and gas prices simultaneously.

5.6.2 Methodology

To assess the impact of electricity price and gas price volatility on DG and CHP investments, we incorporated a log-normal distribution on the prices into the DG and CHP 20-year life-cycle cash flow analysis underlying the tables in Section 5.4. We assigned the mean of the distribution to the EIA national level energy price projections, and used a percentage of the mean as a standard deviation. In this case, energy price varies along the mean, and the variation increases over the projected period. This approach reflects the expectation of more uncertainty and risk as the analysis ventures farther into the future.

The scenarios we ran to assess the impact of price volatility on DG/CHP project economics all assumed the installation of a 5 MW ARES on-site generation project. The investor perspectives were: 1) commercial sector owner/operator of baseload power-only DG; 2) industrial sector owner/operator of CHP supplying thermal load; and 3) ESCO with a CHP system sized to meet the thermal load of an industrial customer.

- To assess the impact of gas price volatility alone, we used a lognormal distribution on gas prices with two different standard deviations, one equal to 15 percent and another equal to 25 percent of the mean gas price. The higher percentage reflects a more volatile scenario. Figure 5-2 shows the range of commercial sector natural gas prices under the 15 percent standard deviation scenario.
- To assess the impact of electricity price volatility alone, we used a lognormal distribution on electricity prices with two different standard deviations, one equal to 15 percent and another equal to 25 percent of the mean electricity price. Figure 5-3 shows the range of commercial sector electricity prices under the 15 percent standard deviation scenario.
- To assess the impact of the combined volatility of gas and electricity prices, we used lognormal distributions on gas and electricity prices with standard deviations equal to

15 percent and 25 percent of the mean electricity and mean gas prices. We also assumed that gas and electricity prices are independent of each other.

Figure 5-2
Gas Price Volatility: S.D. = 15% of Mean Price

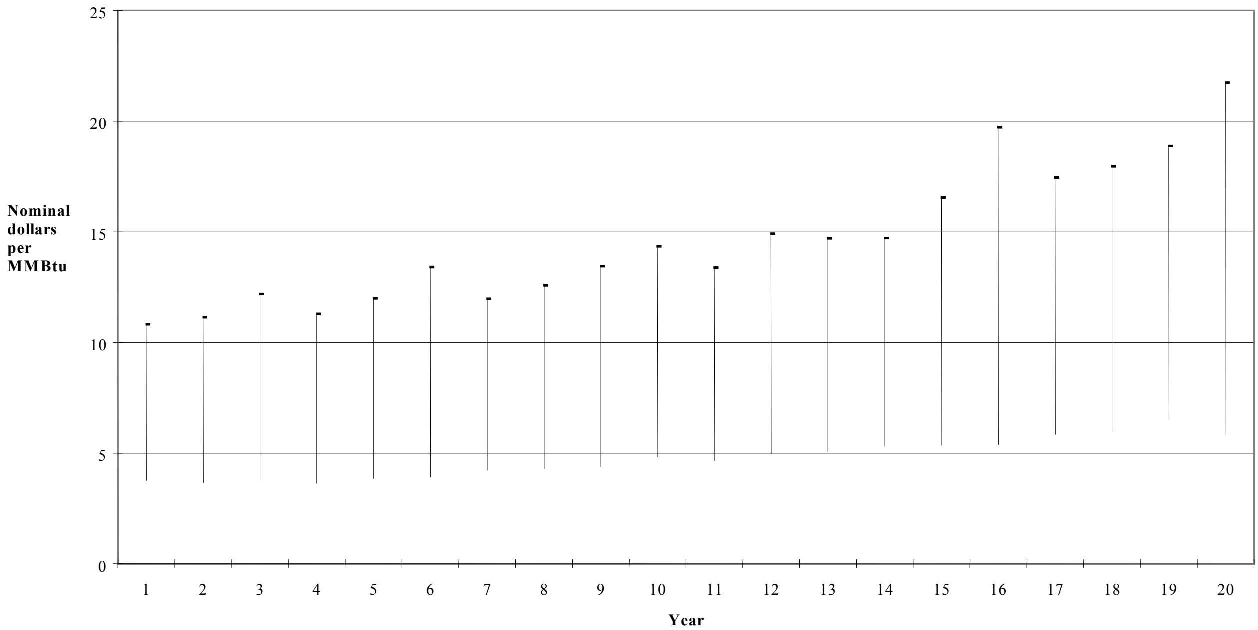
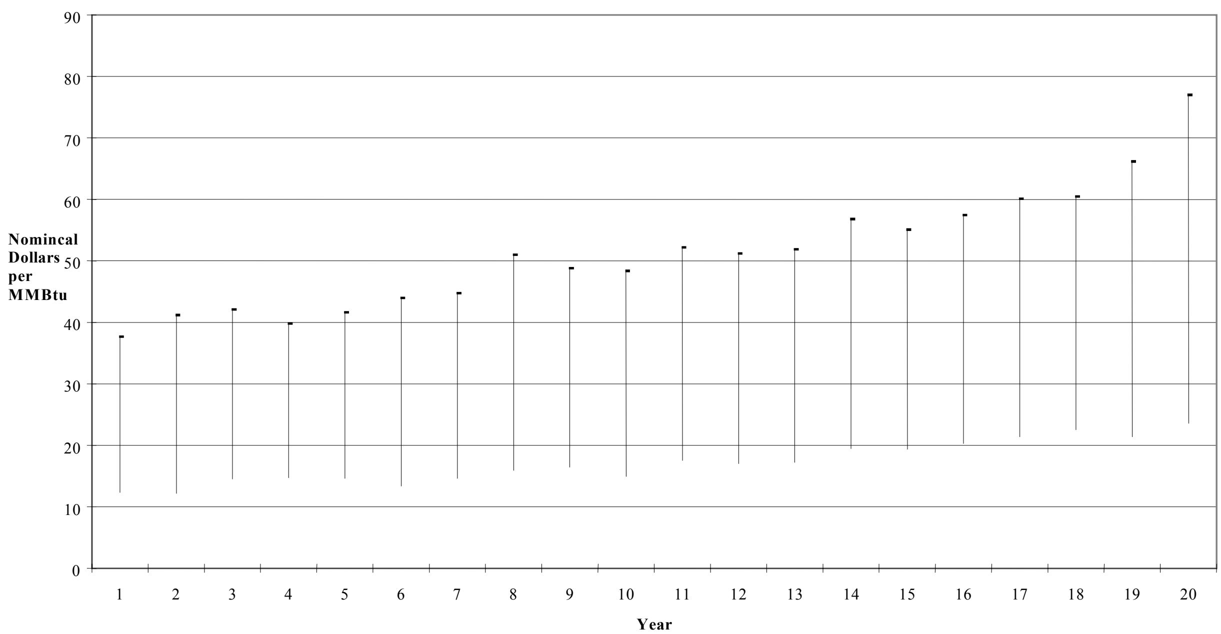


Figure 5-3
Electricity Price Volatility: S.D. = 15% of Mean Price



These analytical results do not provide any insight into the psychological impact of price volatility on investment decisions.

5.6.3 Results

The focus of our analysis was to examine the impact of volatile prices on net present value (NPV). Specifically, in each scenario, we calculated the probability of the investment resulting in a negative NPV for the investor.

5.6.3.1 Owner/Operator, Commercial Sector DG

In this scenario, a commercial firm plans to install a 5 MW ARES technology to provide all of its electricity needs. Table 5-5 below presents the economic assessment results representing a base case of non-volatile natural gas and electricity price projections. This base case offers a seven-year payback to the commercial sector energy user, with an NPV of $3.4 million.

Table 5-5
Economic Assessment Results
DG Commercial Sector, Baseload Power Only

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)
Base Case	5,400,000	3,443,082	7

Figure 5-4 shows the distribution curves of the NPV of a DG investment when gas prices are volatile throughout the projection period at the two different standard deviation scenarios. The chart shows that the probability of a negative NPV is higher with higher volatility. It is critical to note, however, that the probability of a negative NPV is still quite low (0.1 percent for the 25 percent standard deviation case), and that the probability is in fact zero for the 15 percent standard deviation case.

Figure 5-5 shows the distribution curves of the NPV of a DG investment when electricity prices are volatile throughout the projection period at the two different standard deviation scenarios. Similar to the gas price results, the probability of a negative NPV is low (0.8 percent for the 25 percent standard deviation case), and it increases as volatility increases. More interestingly, the results also show that the probability of a negative NPV is higher with electricity price volatility than with gas price volatility. This is perhaps not surprising since electricity prices are high relative to gas prices, with most of the benefits of the investment flowing from electricity savings.

Figure 5-4
Distribution of DG NPV: Gas Price Volatility Scenario

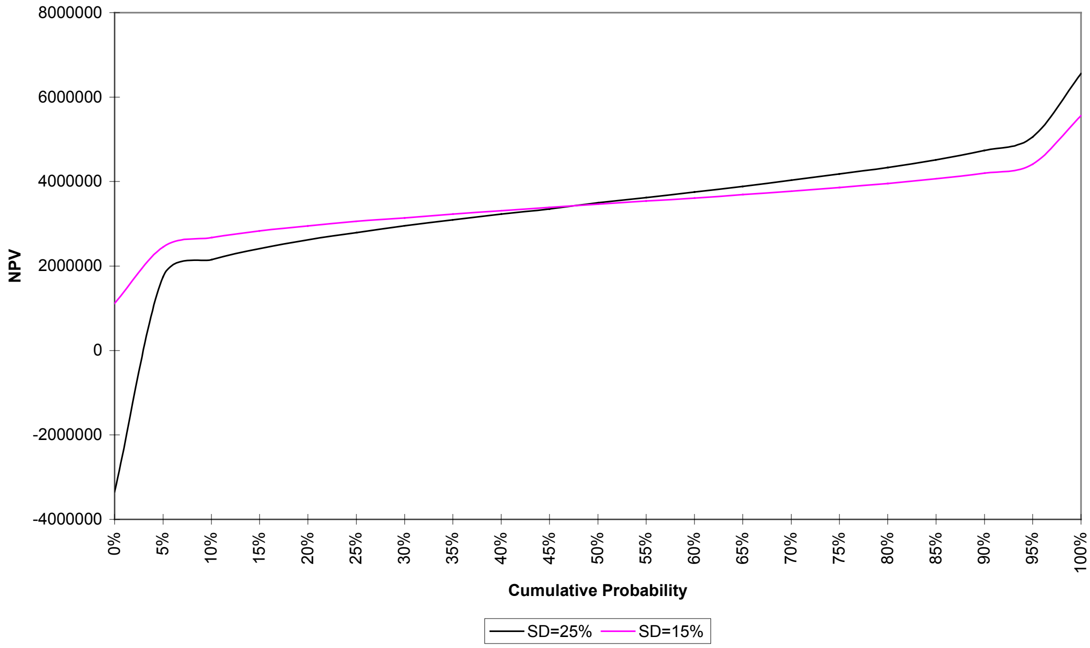


Figure 5-5
Distribution of DG NPV: Electricity Price Volatility Scenario

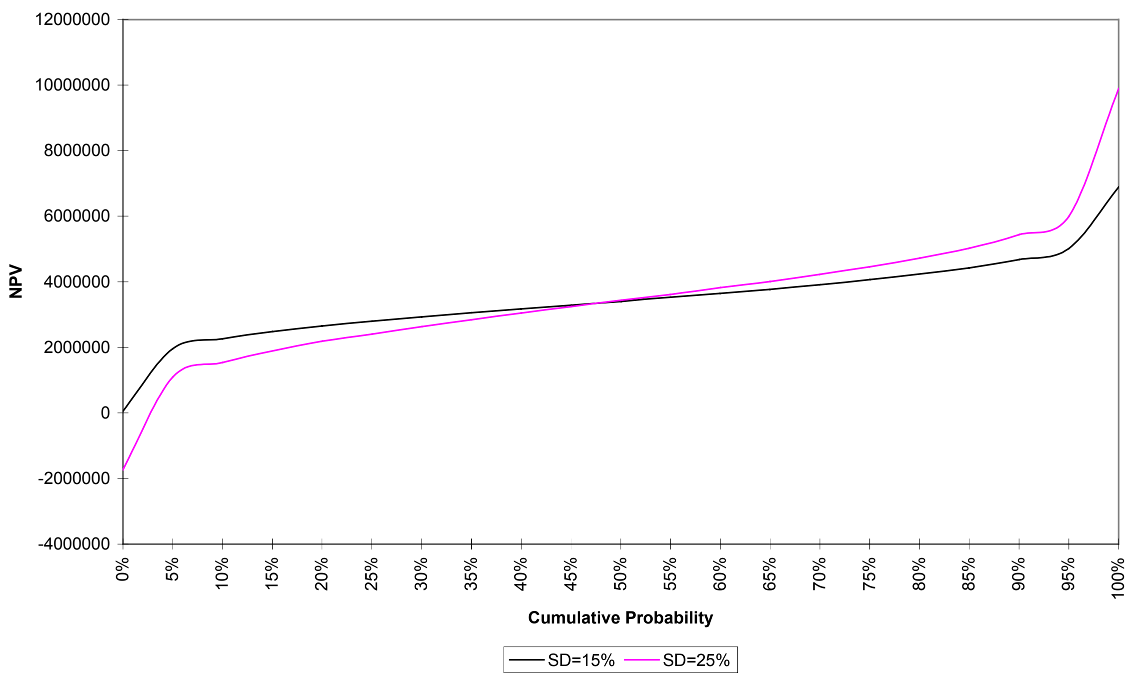
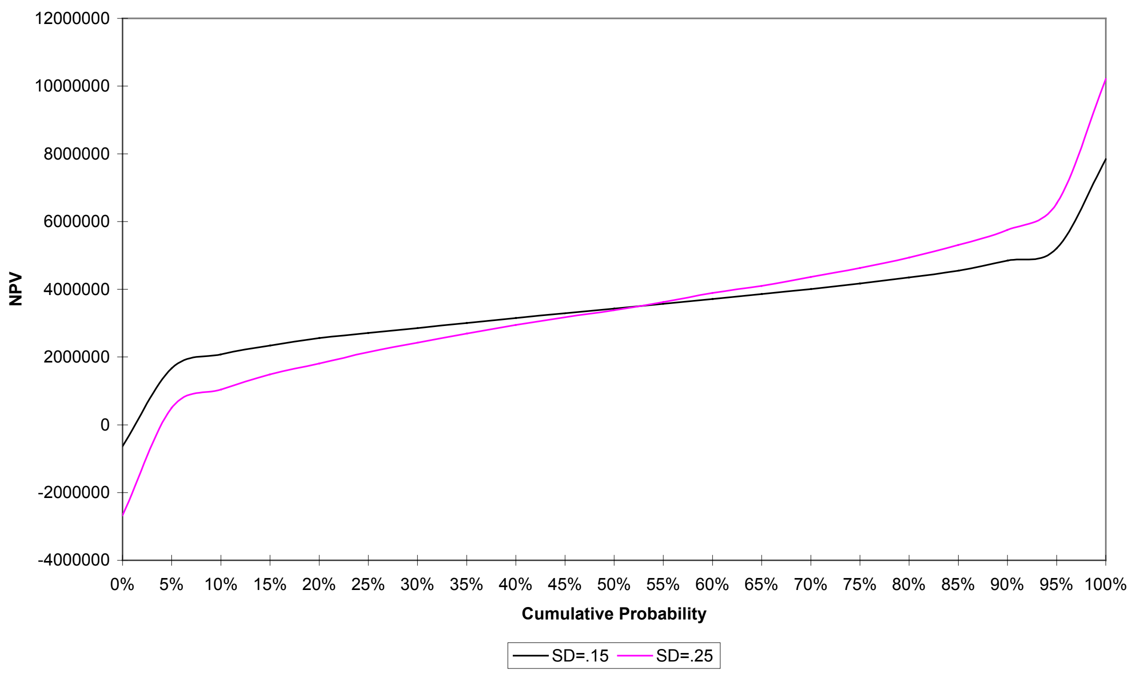


Figure 5-6 shows the distribution curves of the NPV of a DG investment when both gas and electricity prices are volatile throughout the projection period at the two different standard deviation scenarios. As expected, the results show that the probability of a negative NPV is higher as price volatility increases. The probability of a negative NPV is now higher than in the gas only and electricity only cases, with the probability reaching two percent in the 25 percent standard deviation case.

With these low probabilities of achieving a negative NPV, one would expect that a commercial sector end-use customer would not be too concerned about energy price volatility when evaluating a DG/CHP project. Furthermore, the DG owner/operator can always exercise their option of hedging the DG fuel price risk by engaging in long-term price contracts.

Figure 5-6
Distribution of DG NPV: Electricity and Gas Price Volatility Scenario



5.6.3.2 Owner/Operator, Industrial Sector CHP

In this scenario, an industrial firm plans to install a 5 MW CHP plant using an ARES technology with heat recovery to meet all of its thermal energy needs, retiring the existing gas boiler that is currently supplying the thermal loads. The firm will sell any residual electricity generated to the grid at a buy-back price of 80 percent of the end-use price. Table 5-6 presents the results of the cash flow analysis under a base case scenario of non-volatile gas and electricity price projections.

Table 5-6
Economic Assessment Results
Industrial Sector CHP

	Initial Investment ($)	Net Present Value ($)	Simple Payback (# of yrs)
Base Case	6,341,860	8,205,725	5

Similar to the power-only commercial sector DG scenario, we analyzed scenarios incorporating volatility into gas prices only, into electricity prices only, and into both gas and electricity prices.

In all the scenarios analyzed for this type of investment, the probability of the investor obtaining a negative NPV is zero. That is, none of the price volatility scenarios with standard deviations of 15 percent or 25 percent of the mean price produces a negative NPV. With these results, it is expected that CHP investors will not be overly concerned with volatile prices, although the investment returns might fluctuate with price spikes or even be lower than projected.

The analysis show that a CHP investment is less sensitive to price volatility than a power-only DG investment. This is true in this analysis for the same reason that central utility power plants are less sensitive than DG systems: higher efficiency.

5.6.3.3 ESCO with Industrial CHP Customer

In this scenario, an ESCO plans to install a 5 MW CHP plant using an ARES technology with heat recovery at an industrial customer's facility, sized to meet the customer's thermal load. The ESCO will sell the thermal energy (steam) and electricity generated to the customer at a ten percent discount off the customer's current thermal and electricity costs. The ESCO will sell any residual electricity generated to the grid at a buy-back price of 80 percent of the end-use price. Table 5-7 presents the results of the cash flow analysis under a base case non-volatile gas and electricity price projections.

Table 5-7
Economic Assessment Results
ESCO with Industrial CHP Customer, Base Case

	Initial Investment ($)	Net Present Value ($)	Simple Payback (no. of years)
Base Case	6,341,860	3,800,242	6

Similar to the results of the industrial sector CHP owner/operator case, none of the scenarios generated a positive probability of a negative NPV. That is, none of the price volatility scenarios with standard deviations of 15 percent and 25 percent of the mean price produces a negative NPV. These results suggest that ESCOs investing in CHP to serve industrial customers are unlikely be concerned with energy price volatility. And, like many larger end-use customers, they can engage in hedging the CHP plant fuel price risk by engaging in long-term price contracts or employing other risk management tools.

5.6.4 Summary and Conclusions

The quantitative analysis performed for this study incorporated a lognormal distribution on a set of gas and electricity price forecasts underlying life-cycle cash flow analyses in a variety of DG/CHP investment scenarios. We analyzed several risk scenarios representing both owner/operator (end-use energy customer) and ESCO investors, featuring volatility in gas prices only, electricity prices only, and both gas and electricity prices simultaneously. The analysis yielded the following results:

- While higher energy price volatility leads to higher probability of a negative NPV, the probability of achieving a negative NPV is very small in all of the scenarios examined.
- Future gas price and electricity price volatility do not significantly impact the NPV of a CHP or DG investment.
- Electricity price volatility has a relatively larger impact on an investment's NPV than gas price volatility.
- A CHP installation reflects a more stable investment, as it is less affected by energy price volatility than a power-only DG investment.

5.7
Summary and Conclusions

In this volume, we have characterized DG/CHP systems, described the end-use customers and ESCOs who are the current and potential owners and operators of such systems, summarized their perceptions and experiences, addressed volatility and its general effects in DG/CHP markets, and analyzed the economics of DG and CHP projects under a variety of energy price volatility scenarios. Both the quantitative analysis and the intelligence gathered from interviews with end-use customers, ESCOs, utilities and manufacturers suggest the following conclusions about the impact of energy price volatility on the emerging DG/CHP market.

<u>Industrial Sector DG/CHP</u>. The economics of on-site generation, and CHP in particular, is barely impacted by volatility on either the natural gas or electricity side. The fact that the overwhelming majority of installed CHP is in the industrial sector reflects the positive economics of being able to serve large thermal loads with heat recovered from on-site generation that serves the entire facility's electrical load, often with excess to sell to the grid. Potential impacts of volatility are dampened in this sector through use of dual-fuel CHP technologies and sophisticated commodity purchasing practices with use of price risk management tools. Investors in this sector tend to view DG/CHP as one in a set of energy management strategies that work together to address energy price challenges and minimize costs. They place higher confidence in the functioning of the relatively mature natural gas marketplace than in the immature electricity marketplace, and generally anticipate that further deregulation on the electric side will decrease the opportunity for participants to game the system and upset prices.

<u>Commercial Sector DG/CHP</u>. With fewer opportunities for CHP, less ability to engage in commodity purchasing and price risk management, and less experience with and awareness of DG/CHP technologies, the fact that volatility does not significantly impact the NPV of commercial sector DG/CHP investments is less meaningful. Uncertainty surrounding DG/CHP investments tends to be complicated by uncertainty about future levels and relationships of natural gas and electricity prices. Competing uses for capital, typically in high-visibility projects, push energy project investments down the priority queue, and harsh financial criteria such as one-year paybacks constrict opportunities. Drivers of interest in on-site generation include the high cost of power outages and the need for high-quality, reliable power. Taking these factors together, some commercial sector customers with interest in DG/CHP are looking for ESCOs to install, own and operate on-site generation for them, selling electricity and perhaps thermal energy to them at a discount relative to the prices they currently pay. This arrangement transfers price risk to the ESCO and allows customers to focus on their core business and on achieving additional energy savings through less capital-intensive projects. For other customers, however, the need for a more stable price environment is leading to postponement of serious consideration of DG/CHP.

Residential Sector DG/CHP. With no products commercially available to residential customers yet, the impacts of price volatility on future DG/CHP investment decisions may only be surmised from research posing "what if" scenarios to potential customers. Focus group results indicate that because residential consumers view obtaining electricity as satisfying a basic household need, they tend to view DG as an equal substitute for grid electricity, even in areas affected by outages and price spikes. Outages, interruptions and power quality disturbances are perceived as merely annoying, not drivers for considering baseload DG. There appears to be some interest in DG as back-up power. With the degree of protection from volatile market prices afforded by regulated rates, especially on the electric side, it is not surprising that volatility is not a consideration in hypothetical residential DG purchase decisions.

ESCOs and DG/CHP. ESCOs active in DG/CHP plant ownership and operation possess the sophistication in commodity purchasing and risk management and knowledge of technologies that allow them to perceive opportunities for profit in developing DG/CHP projects to serve the thermal and electrical loads of commercial and industrial customers. The desire for price stability on the part of end-use customers, combined with an interest in DG/CHP, makes an ESCO arrangement potentially attractive. ESCOs, like industrial customers, tend to perceive the natural gas market as relatively mature and stable, with many more tools available to manage price risk. Thus, the lack of sensitivity of ESCO investments in DG/CHP projects reflects the current approach of ESCOs who have the skills and ability necessary to engage in DG/CHP projects to serve end-use customers.

The above conclusions above suggest that the impact of price volatility on the emergence of DG/CHP is neutral to slightly positive on the market as a whole.

A

APPENDIX A: GAS RATEMAKING FUNDAMENTALS

Gas Utility Rate Fundamentals

Revenue Requirement

At the core of traditional cost-of-service regulation is the concept of the revenue requirement of the utility. The revenue requirement is the annual amount of revenue that is necessary to recover the utility's annualized costs plus a fair return on the capital investment.

There are five basic concepts central to the construction of the revenue requirement. These are:

- Base Period / Test Period – The specific period of time used to estimate representative costs for utility service. The costs can reflect a period of recent history, a forecasted period, or a combination of both.
- Rate Base – The capital investment in the distribution system upon which the LDC is allowed to earn a return. Generally the rate base is equal to the initial capital investment minus the cumulative depreciation incurred by those facilities since they were placed in service. Regulators can reduce the rate base if they decide that any facilities are not "used and useful."
- Rate of Return / Capital Structure – The rate of return is the annual percentage that regulators determine provides reasonable earnings. The rate is calculated by a weighted average of the cost of debt (a function of interest rates) and return on equity approved by the regulators. The capital structure of the utility or the utility holding company determines the weighting of these factors.
- Cost of Service – The cost of service is the sum of the following components:
  - Operating expenses – The annual expenses incurred by the LDC including salaries, benefits, administrative costs, and others. The cost of gas is also a major expense item. Often the cost of gas is considered separately using a cost of gas adjustment (CGA) mechanism.
  - Depreciation – The annual depreciation of the rate base.
  - Return on investment – The allowable earnings on the rate base.[1]

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[1] Actual earnings can be either less than or greater than the allowable earnings. Most often this occurs because the actual throughput volumes differ from those assumed in the ratemaking process, or the actual costs differ

- Ratemaking and Pro-forma Adjustments – Adjustments for "known and measurable" differences between costs incurred in the test period and future costs. A change in an applicable tax rate is often a source of "known and measurable" adjustments. Similarly, one-time expenses are generally removed from the cost of service.

Cost Allocation

Once the revenue requirement has been constructed, the utility allocates the costs to each customer class and individual service based upon a cost allocation study that identifies the cost to serve each customer class. The utility prepares an initial cost allocation study and submits the study to the state regulators for approval. The approval process can require a fully litigated proceeding before the regulatory body.

The cost allocation process involves three basic steps:

- Functionalization: Costs are divided into basic functions such as production, storage, transmission and distribution in accordance with the uniform system of accounts.
- Classification: Costs are assigned or prorated into categories, generally designated as demand, commodity, or customer costs.
- Allocation to customer classes: Functionalized and classified costs are further allocated to individual customer classes and services.

Rate Design

Once all of the costs have been determined and classified, the utility calculates the rates for each service. This process requires an estimate or projection of the number of customers and the amount of consumption for each service. These estimates, called the "billing determinants," are subject to the same process of review in the state regulatory process as the revenue requirement and cost allocation determinations.

For the LDC to recover the revenue requirement, the rates are designed so that:

Sum (Rate X Billing Determinant) = The Revenue Requirement

Utility rates for firm service are not generally designed to recover costs exclusively on a volumetric bases. Rather, the tariff rate generally provides for a fixed monthly customer charge that recovers some portion of the LDC's fixed costs regardless of the level of consumption. The tariff generally recovers the remainder of the revenue requirement via a "per unit" charge applied to each unit of consumption.

It is important to note that ***it is extremely rare for the rate structure of an LDC to collect all of the fixed costs of the system from the customer charges***. Rather, most gas utilities collect 30

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from the test period costs adopted in the rate proceeding. As a result, the actual rate of return can also be different from the allowable rate of return.

percent or more of the fixed costs from the volumetric portion of the rate. As a result, if actual throughput deviates substantially from the projected throughput implicit in the billing determinants, the actual recovered costs will also deviate from the projected revenue requirement. This can lead to over- or under-recovery of costs. However, as was noted earlier, in practice the risk is somewhat asymmetric, with greater risk of under-recovery.

Many utilities employ a block rate structure for their volumetric charges. Generally, the rate for the initial block is greater than the rate for subsequent blocks. The objective is to allow for the recovery of most of the fixed costs of the distribution system even if throughput is somewhat lower than expected. The block structure also limits the amount of over-collection should throughput be higher than expected.

Because the process of designing rates results in different cost burdens on various customer classes, rate design is influenced by political considerations. While the entire proceeding is documented according to accounting standards and consistent with case precedent within the state, the result of the rate design process must provide a fair and politically acceptable burden to the broad range of stakeholders.

Gas Cost Recovery

Under the traditional cost of service model for gas utility rates, the cost of the gas and the cost of the transportation storage services needed to bring the gas to the LDC's Citygate are expenses that are directly recovered in the utility rates with no profit or earnings. Since these expenses represent a large percentage of the consumers costs, most state regulators create a separate "tracker" account for these charges, most often called cost of gas accounts (CGA). The specifics of these accounts may differ from state to state in terms of how often the consumers' cost of gas is adjusted (e.g., monthly, bi-monthly, quarterly, semi-annually). To the extent that the actual gas costs differ from those costs that are reflected in the rates, the positive or negative balances are accumulated in a "true-up" account and are surcharged or refunded to customers through adjustments to the CGA in a subsequent period.

Gas Cost Recovery Before and After the Natural Gas Pipeline Act of 1978

Prior to 1985, gas prices were relatively easy to forecast over the short-term. Prices were generally set under the terms of long-term contracts, the behavior of which was relatively well understood. However, as short-term and spot markets for gas developed, gas prices became much more volatile and harder to predict. As a result, there were significant increases in the dollars accrued in the CGA accounts.

Prior to the restructuring of the interstate pipeline industry that was implemented through FERC Orders 436/500 and 636, LDCs purchased virtually all of their gas supplies in the form of bundled Citygate service. Both the cost of wellhead gas supplies and the cost of transportation service were included in the bundled Citygate sale and included in the CGA mechanism. In the wake of pipeline unbundling, these costs were separated. Some states responded by creating separate trackers for transportation costs in their CGAs, while other states continued to combine the cost in a unified account.

B

APPENDIX B: GLOSSARY OF KEY ENERGY MARKET TRADING AND PRICE VOLATILITY TERMS

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

Arbitrage A trading strategy that takes advantage of two or more securities or time periods being mispriced relative to each other.

Bidweek Transactions Firm commitments to buy or sell a uniform quantity of gas for each day in the following month. The term "bidweek" refers to the final days in the month when contracts for the next month's deliveries are signed. Trade publications collect data from the market participants and compile the prices for monthly firm contracts entered into in the last 5 days, and publish the midpoint and range of the transaction prices.

Black-Scholes Model The Black-Scholes Model is used to estimate the value of an option, and hence can be used to determine the appropriate price that a rational investor would pay for that option. The key unknown in the Black-Scholes model is the expected standard deviation of daily returns for the asset.

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

Crack Spread A commodity-product spread involving the purchase of crude oil futures and the sale of gasoline and heating oil futures, in order to establish a refining margin.

Dual-Fired Capacity The ability of customers to convert to another fuel at short notice. Equipment with the capacity to switch from oil to natural gas.

Futures Contracts	Firm commitments to make or accept delivery of a specified quantity and quality of a commodity during a specific month in the future at a price agreed upon at the time the commitment is made. (Source: NYMEX)
Gas Prices	
Citygate Price	The price for gas delivered at the citygates. Citygates are the transfer point or measuring station at which upstream pipelines connect to the LDC's distribution system.
Retail Price	The price charged to the ultimate consumer.
Spot Prices	The price for a one-time, open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates. (Source: EIA)
Wellhead Price	The price of crude oil or natural gas at the mouth of the well. (Source: EIA)
Hedging	A trade designed to reduce risk. Usually done by covering future commitments at a fixed price in the future, through an options or futures contract.
Kurtosis	A measure of the degree of peakedness of a data distribution. Often referred to as the "excess" or "excess coefficient" relative to a normal distribution, Kurtosis is a normalized form of the fourth moment of a distribution.
Marginal Prices	The price of the next increment of supply. In electricity markets, marginal prices are often calculated on an hourly basis. Published data generally presents daily averages for weekdays (excluding holidays).
Non-commercial Open Interest	The net non-commercial open interest represents total "long" open interest contracts minus total "short" positions held by non-commercial customers. It represents a reasonable proxy for speculative positions in natural gas futures markets. Natural gas prices tend to increase when net non-commercial open interest is above zero and to decrease when net non-commercial interest is below zero.
Open Interest	The number of open or outstanding contracts for which an individual or entity is obligated to an exchange because that individual or entity has not yet made an offsetting sale or purchase, an actual contract delivery, or in the case of options, exercised the option. (Source: NYMEX)

Options A contract between two parties in which one party has the right, but not the obligation, to buy or sell an underlying asset.

Put Option An option that gives the holder the right (but not the obligation) to sell a specified the futures contract at a fixed price, on or before a specified date. The grantor of the option has the obligation to take delivery of the futures contract if the option is exercised.

Call Option An option that gives the holder the right but not the obligation to buy a futures contract at a fixed price, on or before a specified date. The grantor of the option is obliged to sell the futures contract at the fixed price if the holder exercises the option.

Strike Price The price at which an option holder has the right to buy or sell an underlying commodity/derivative.

Risk-free Rate The rate of interest that can be earned without assuming any risk.

Out-of-the-Money Option An option which has no intrinsic value. A put option is out-of-the-money when its strike price is below the value of the underlying futures contract. A call option is out-of-the money when its strike price is above that of the underlying futures contract.

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

Price Collar Contract between a buyer and seller of a commodity whereby the buyer is assured that he will not have to pay more than some maximum price and whereby the seller is assured of receiving some minimum price. (Source: NYMEX)

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

Return Measure of volatility as a percentage change in prices, rather than in absolute prices. Can be viewed as a measure of expected return on investment, e.g., a 10 percent increase in price represents a 10 percent return on the value of the underlying asset, regardless of whether the 10 percent return represents a $0.20 increase from $2.00 per MMBtu, or a $1.00 increase from $10.00 per MMBtu.

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

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

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

Skewness A measure of the degree of asymmetry of a distribution. If the distribution has a longer tail on one side of the distribution than the other, the distribution is skewed. Variables such as price, which have a theoretical minimum value (zero) but no theoretical maximum value, typically would be expected to have a skewed distribution. Data skewness provides a measure of the asymmetrical market impact of directionally different effects. For example, an increase in demand due to colder than normal weather will typically have a larger upward impact on natural gas price than a similar decrease in demand due to warmer than normal weather.

Spark Spread The difference in value between marketed electricity and the cost of energy used to produce electricity.

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

Wash Trading Wash Trading exists when a market participant makes two or more offsetting trades that act to cancel each other out.

C

APPENDIX C: DESCRIPTIONS OF SELECTED COMMODITY MARKETS

With the exception of electricity, which is not traded on a commodity market, this appendix includes the descriptions of the traded commodities reviewed in this report as published by the market center trading the commodity.

C.1 Henry Hub Natural Gas Market

New York Mercantile Exchange Description and Specifications
Source: www.nymex.com

Natural gas plays a major role in the United States energy profile, where it accounts for almost a quarter of total energy consumption. Its market share is likely to expand because of the favorable competitive position of gas in relation to other fuels, and the tightening environmental standards for fuel combustion. Industrial users and electric utilities together account for 59% of the market; commercial and residential users combined are 42%.

The industry has gone through a metamorphosis since the enactment of the Natural Gas Policy Act of 1978, changing from an almost totally regulated industry to one that today largely operates as a free market. The New York Mercantile Exchange, Inc. launched the world's first natural gas futures contract in April 1990. Volume and open interest have grown rapidly, establishing the contract as the fastest growing instrument in Exchange history.

The Exchange marked another milestone in the energy markets in October 1992 when it launched options on natural gas futures, giving market participants additional flexibility in managing their market risk.

Industry participation in the natural gas futures market comprises a wide cross-section of the industry from producers to end-users. Many natural gas and electric utilities either use the NYMEX Division natural gas futures and options contracts, or are considering doing so. A number of state utility regulators have given permission to utilities in their jurisdictions to use the NYMEX Division markets or are considering such proposals.

Recent legislation concerning air pollution control should only contribute to the market's further growth.

From a market of stable but controlled prices and long-term contracts, the natural gas market has emerged as a dynamic, highly competitive business with flexible pricing, an active spot market, and widespread use of short- to medium-term contracts. This is causing a fundamental change in the way each of the traditional segments of the industry operate: producers, pipelines, gas utilities, and industrial users.

The radical change has also led to the development and rapid growth of a business that did not exist a few years ago, the natural gas marketer who links buyers with sellers and often arranges pipeline transportation for his customers. The natural gas futures contract is especially well suited to manage the increasing price risk that has accompanied these market changes.

Trading Unit

Futures: 10,000 million British thermal units (mmBtu).
Options: One NYMEX Division natural gas futures contract.

Price Quotation

Futures and Options: Dollars and cents per mmBtu, for example, $2.850 per mmBtu.

Trading Hours

Futures and Options: Open outcry trading is conducted from 10:00 A.M. until 2:30 P.M. (natural gas futures and options will close at 2:45 P.M. on any futures termination day that falls on a Wednesday).

After hours futures trading is conducted via the NYMEX ACCESS® internet-based trading platform beginning at 3:15 P.M. on Mondays through Thursdays and concluding at 9:00 A.M. the following day. On Sundays, the session begins at 7:00 P.M. All times are New York time. Natural Gas futures and options will close at 2:45 P.M. on any futures termination day that falls on a Wednesday

Trading Months

Futures: 72 consecutive months commencing with the next calendar month (for example, on January 2, 2002, trading occurs in all months from February 2002 through January 2008).

Options: 12 consecutive months, plus contracts initially listed 15, 18, 21, 24, 27, 30, 33, 36, 39, 42, 45, 48, 51, 54, 57, 60, 63, 66, 69, and 72 months out on a March, June, September, December cycle.

Minimum Price Fluctuation

Futures and Options: $0.001 (0.1¢) per mmBtu ($10.00 per contract).

Maximum Daily Price Fluctuation

Futures: $1.00 per mmBtu ($10,000 per contract) for all months. If any contract is traded, bid, or offered at the limit for five minutes, trading is halted for 15 minutes. When trading resumes, expanded limits are in place that allow the price to fluctuate by $2.00 in either direction of the previous day's settlement price. There are no price limits on any month during the last three days of trading in the spot month.

Options: No price limits.

Last Trading Day

Futures: Trading terminates three business days prior to the first calendar day of the delivery month.

Options: Trading terminates at the close of business on the business day immediately preceding the expiration of the underlying futures contract.

Exercise of Options

By a clearing member to the Exchange clearinghouse not later than 5:30 P.M. or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including the options expiration.

Option Strike Prices

Twenty strike prices in increments of $0.05 (5¢) per mmBtu above and below the at-the-money strike price in all months, plus an additional 20 strike prices in increments of $0.05 per mmBtu above the at-the-money price will be offered in the first three nearby months, and the next 10 strike prices in increments of \$0.25 (25¢) per mmBtu above the highest and below the lowest existing strike prices in all months for a total of at least 81 strike prices in the first three nearby months and a total of at least 61 strike prices for four months and beyond. The at-the-money strike price is nearest to the previous day's close of the underlying futures contract. Strike price boundaries are adjusted according to futures price movements.

Delivery Location

Sabine Pipe Line Co.'s Henry Hub in Louisiana. Seller is responsible for the movement of the gas through the Hub; the buyer, from the Hub. The Hub fee will be paid by seller.

Delivery Period

Delivery shall take place no earlier than the first calendar day of the delivery month and shall be completed no later than the last calendar day of the delivery month. All deliveries shall be made at as uniform as possible an hourly and daily rate of flow over the course of the delivery month.

Alternate Delivery Procedure (ADP)

An alternate delivery procedure is available to buyers and sellers who have been matched by the Exchange subsequent to the termination of trading in the spot month contract. If buyer and seller agree to consummate delivery under terms different from those prescribed in the contract specifications, they may proceed on that basis after submitting a notice of their intention to the Exchange.

Exchange of Futures For, or in Connection with, Physicals (EFP) or Swaps (EFS)

The commercial buyer or seller may exchange a futures position for a physical position or a swaps position of equal quantity by submitting a notice to the Exchange. EFPs and EFSs may be used to either initiate or liquidate a futures position.

Quality Specifications

Pipeline specifications in effect at time of delivery.

Position Accountability Limits

Any one month / all months: 12,000 net futures, but not to exceed 1,000 in the last three days of trading in the spot month or 5,000 in any one month.

Trading Symbols

Futures: NG
Options: ON

C.2 Light Sweet Crude Oil

New York Mercantile Exchange Description and Specifications
Source: www.nymex.com

Crude oil is the world's most actively traded commodity. Over the past decade, the NYMEX Division light, sweet (low-sulfur) crude oil futures contract has become the world's most liquid forum for crude oil trading, as well as the world's largest-volume futures contract trading on a physical commodity. Because of its excellent liquidity and price transparency, the contract is used as a principal international pricing benchmark.

The contract's delivery point is Cushing, Oklahoma, the nexus of spot market trading in the United States, which is also accessible to the international spot markets via pipelines. By providing for delivery of several grades of domestic and internationally traded foreign crudes, the futures contract is designed to serve the diverse needs of the physical market.

Light, sweet crudes are preferred by refiners because of their relatively high yields of high-value products such as gasoline, diesel fuel, heating oil, and jet fuel.

Trading Unit

Futures: 1,000 U.S. barrels (42,000 gallons).
Options: One NYMEX Division light, sweet crude oil futures contract.

Price Quotation

Futures and Options: Dollars and cents per barrel.

Trading Hours

Futures and Options: Open outcry trading is conducted from 10:00 A.M. until 2:30 P.M.

After hours futures trading is conducted via the NYMEX ACCESS® internet-based trading platform beginning at 3:15 P.M. on Mondays through Thursdays and concluding at 9:00 A.M. the following day. On Sundays, the session begins at 7:00 P.M. All times are New York time.

Trading Months

Futures: 30 consecutive months plus long-dated futures initially listed 36, 48, 60, 72, and 84 months prior to delivery.

Additionally, trading can be executed at an average differential to the previous day's settlement prices for periods of two to 30 consecutive months in a single transaction. These calendar strips are executed during open outcry trading hours.

Options: 12 consecutive months, plus three long-dated options at 18, 24, and 36 months out on a June/December cycle.

Minimum Price Fluctuation

Futures and Options: $0.01 (1¢) per barrel ($10.00 per contract).

Maximum Daily Price Fluctuation

Futures: Initial limits of $3.00 per barrel are in place in all but the first two months and rise to $6.00 per barrel if the previous day's settlement price in any back month is at the $3.00 limit. In the event of a $7.50 per barrel move in either of the first two contract months, limits on all months become $7.50 per barrel from the limit in place in the direction of the move following a one-hour trading halt.

Options: No price limits.

Last Trading Day

Futures: Trading terminates at the close of business on the third business day prior to the 25th calendar day of the month preceding the delivery month. If the 25th calendar day of the month is a non-business day, trading shall cease on the third business day prior to the last business day preceding the 25th calendar day.

Options: Trading ends three business days before the underlying futures contract.

Exercise of Options

By a clearing member to the Exchange clearinghouse not later than 5:30 P.M., or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including the option's expiration.

Options Strike Prices

Twenty strike prices in increments of $0.50 (50¢) per barrel above and below the at-the-money strike price, and the next ten strike prices in increments of $2.50 above the highest and below the lowest existing strike prices for a total of at least 61 strike prices. The at-the-money strike price is nearest to the previous day's close of the underlying futures contract. Strike price boundaries are adjusted according to the futures price movements.

Delivery

F.O.B. seller's facility, Cushing, Oklahoma, at any pipeline or storage facility with pipeline access to TEPPCO, Cushing storage, or Equilon Pipeline Co., by in-tank transfer, in-line transfer, book-out, or inter-facility transfer (pumpover).

Delivery Period

All deliveries are ratable over the course of the month and must be initiated on or after the first calendar day and completed by the last calendar day of the delivery month.

Alternate Delivery Procedure (ADP)

An alternate delivery procedure is available to buyers and sellers who have been matched by the Exchange subsequent to the termination of trading in the spot month contract. If buyer and seller agree to consummate delivery under terms different from those prescribed in the contract specifications, they may proceed on that basis after submitting a notice of their intention to the Exchange.

Exchange of Futures for, or in Connection with, Physicals (EFP)

The commercial buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position.

Deliverable Grades

Specific domestic crudes with 0.42% sulfur by weight or less, not less than 37° API gravity nor more than 42° API gravity. The following domestic crude streams are deliverable: West Texas Intermediate, Low Sweet Mix, New Mexican Sweet, North Texas Sweet, Oklahoma Sweet, South Texas Sweet.

Specific foreign crudes of not less than 34° API nor more than 42° API. The following foreign streams are deliverable: U.K. Brent and Forties, and Norwegian Oseberg Blend, for which the seller shall receive a 30¢-per-barrel discount below the final settlement price; Nigerian Bonny Light and Colombian Cusiana are delivered at 15¢ premiums; and Nigerian Qua Iboe is delivered at a 5¢ premium.

Inspection

Inspection shall be conducted in accordance with pipeline practices. A buyer or seller may appoint an inspector to inspect the quality of oil delivered. However, the buyer or seller who requests the inspection will bear its costs and will notify the other party of the transaction that the inspection will occur.

Position Accountability Limits

Any one month/all months: 20,000 net futures, but not to exceed 1,000 in the last three days of trading in the spot month.

Margin Requirements

Margins are required for open futures or short options positions. The margin requirement for an options purchaser will never exceed the premium.

Trading Symbols

Futures: CL
Options: LO

C.3 Heating Oil

New York Mercantile Exchange Description and Specifications
Source: www.nymex.com

Heating oil, also known as No. 2 fuel oil, accounts for about 25% of the yield of a barrel of crude, the second largest "cut" after gasoline. In its early years, the heating oil futures contract attracted mainly heating oil wholesalers and large consumers. It soon became apparent that the contract was also being used to hedge diesel fuel, which is chemically similar to heating oil, and jet fuel, which trades in the cash market at a usually stable premium to NYMEX Division heating oil futures.

Today, a wide variety of businesses, including oil refiners, wholesale marketers, heating oil retailers, trucking companies, airlines, and marine transport operators, as well as other major consumers of fuel oil, have embraced this contract as a risk management vehicle and pricing mechanism. The recent imposition of strict federal sulfur standards for diesel fuel have the potential to increase price volatility in some markets.

Seasonal and economic factors influence the relative prices of heating oil, gasoline, natural gas, propane, and crude oil. By spread trading heating oil futures against other NYMEX Division energy futures contracts, businesses are able to fix margins among products. Marketers and traders can also lock in a return for carrying heating oil inventory by spread trading calendar months.

Because NYMEX Division heating oil futures are traded over 18 consecutive months, traders can implement hedging strategies that encompass two winter heating seasons.

Trading Unit

Futures: 42,000 U.S. gallons (1,000 barrels).
Options: One NYMEX Division heating oil futures contract.

Price Quotation

Futures and Options: In dollars and cents per gallon: for example, $0.7527 (75.27¢) per gallon.

Trading Hours

Futures and Options: Open outcry trading is conducted from 10:05 A.M. until 2:30 P.M.

After hours futures trading is conducted via the NYMEX ACCESS® internet-based trading platform beginning at 3:15 P.M. on Mondays through Thursdays and concluding at 9:00 A.M. the following day. On Sundays, the session begins at 7:00 P.M. All times are New York time.

Trading Months

Futures: Trading is conducted in 18 consecutive months commencing with the next calendar month (for example, on January 2, 2002, trading occurs in all months from February 2002 through July 2003).

Options: 18 consecutive months.

Minimum Price Fluctuation

Futures and Options: \$0.0001 (0.01¢) per gallon (\$4.20 per contract).

Maximum Daily Price Fluctuation

Futures: Initial limits of \$0.06 (6¢) per gallon are in place in all but the first two months and rise to \$0.09 (9¢) per gallon if the previous day's settlement price in any back month is at the \$0.06 per gallon limit. In the event of a \$0.20 (20¢) per gallon move in either of the first two contract months, limits on all months become \$0.20 per gallon from the limit in place in the direction of the move following a one-hour trading halt.

Options: No price limits.

Last Trading Day

Futures: Trading terminates at the close of business on the last business day of the month preceding the delivery month.

Options: Trading ends three business days before the underlying futures contract.

Exercise of Options

By a clearing member to the Exchange clearinghouse not later than 5:30 P.M., or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including the option's expiration.

Options Strike Prices

Twenty strike prices in one-cent-per-gallon increments above and below the at-the-money strike price, and the next ten strike prices in five-cent increments above the highest and below the lowest existing strike prices for a total of at 61 strike prices. The at-the-money strike price is the nearest to the previous day's close of the underlying futures contract. Strike price boundaries are adjusted according to the futures price movements.

Delivery

F.O.B. seller's facility in New York Harbor, ex-shore. All duties, entitlements, taxes, fees, and other charges paid. Requirements for seller's shore facility: capability to deliver into barges. Buyer may request delivery by truck, if available at the seller's facility, and pays a surcharge for truck delivery. Delivery may also be completed by pipeline, tanker, book transfer, or inter- or intra-facility transfer. Delivery must be made in accordance with applicable federal, state, and local licensing and tax laws.

Delivery Period

Deliveries may only be initiated the day after the fifth business day and must be completed before the last business day of the delivery month.

Alternate Delivery Procedure (ADP)

An alternate delivery procedure is available to buyers and sellers who have been matched by the Exchange subsequent to the termination of trading in the spot month contract. If buyer and seller agree to consummate delivery under terms different from those prescribed in the contract specifications, they may proceed on that basis after submitting a notice of their intention to the Exchange.

Exchange of Futures for, or in Connection with, Physicals (EFP)

The commercial buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position.

Grade and Quality Specifications

Generally conforms to industry standards for fungible No. 2 heating oil.

Inspection

The buyer may request an inspection for grade and quality or quantity for all deliveries, but shall require a quantity inspection for a barge, tanker, or inter-facility transfer. If the buyer does not request a quantity inspection, the seller may request such inspection. The cost of the quantity inspection is shared equally by the buyer and seller. If the product meets grade and quality specifications, the cost of the quality inspection is shared jointly by the buyer and seller. If the product fails inspection, the cost is borne by the seller.

Position Accountability Limits

7,000 contracts for all months combined, but not to exceed 1,000 in the last three days of trading in the spot month or 5,000 in any one month.

Margin Requirements

Margins are required for open futures or short options positions. The margin requirement for an options purchaser will never exceed the premium.

Trading Symbols

Futures: HO
Options: OH

C.4 COPPER

New York Mercantile Exchange Description and Specifications
Source: www.nymex.com

Copper, one of the oldest commodities known to man, is a product with fortunes which directly reflect the state of the world economy. It is the world's third most widely used metal, after iron and aluminum, and is primarily used in highly cyclical industries such as construction and industrial machinery manufacturing. Profitable extraction of the metal depends on cost-efficient high-volume mining techniques, and supply is sensitive to the political situation particularly in those countries where copper mining is a government-controlled enterprise.

Copper was first worked about 7,000 years ago. Its softness, color, and presence in nature enabled it to be easily mined and fashioned into primitive utensils, tools, and weapons. Five thousand years ago, man learned to alloy copper with tin, producing bronze and giving rise to a new age.

Thus copper was established as a commodity with commercial value.

By the mid-1800s, Britain, with superior smelting technology, controlled more than three-quarters of the world copper trade. As the proportion of metal to waste in rock declined, it became economical to position smelters and refiners adjacent to mining sites and ship the final product directly to market. The discovery, in the 19th century, of major copper deposits in North America, Chile, and Australia challenged England's preeminent position.

In the early 20th century, new mining and smelting techniques were developed in the United States which made it possible to process lower-grade ores, resulting in a dramatic global expansion of the copper market.

Since the 1950s, more often than not, the copper market has been in backwardation but has gone into contango for significant periods of time.

Copper market participants across the board use COMEX Division high-grade copper futures and options to mitigate price risk, and the copper contracts are used as investment vehicles, as well.

Trading Unit

25,000 pounds.

Price Quotation

Cents per pound. For example, 75.80¢ per pound.

Trading Hours

Open outcry trading is conducted from 8:10 A.M. until 1:00 P.M.

After-hours futures trading is conducted via the NYMEX ACCESS® internet-based trading platform beginning at 3:15 P.M. on Mondays through Thursdays and concluding at 8:00 A.M. the following day. On Sundays, the session begins at 7:00 P.M. All times are New York time.

Trading Months

Trading is conducted for delivery during the current calendar month and the next 23 consecutive calendar months.

Minimum Price Fluctuation

Price changes are registered in multiples of five one hundredths of one cent ($0.0005, or 0.05¢) per pound, equal to $12.50 per contract. A fluctuation of one cent ($0.01 or 1¢) is equal to $250.00 per contract.

Maximum Daily Price Fluctuation

Initial price limit, based upon the preceding day's settlement price is $0.20 (20¢) per pound. Two minutes after either of the two most active months trades at the limit, trading in all months of futures and options will cease for a 15-minute period. Trading will also cease if either of the two active months is bid at the upper limit or offered at the lower limit for two minutes without trading.

Trading will not cease if the limit is reached during the final 20 minutes of a day's trading. If the limit is reached during the final half hour of trading, trading will resume no later than 10 minutes before the normal closing time.

When trading resumes after a cessation of trading, the price limits will be expanded by increments of 100%.

Last Trading Day

Trading terminates at the close of business on the third to last business day of the maturing delivery month.

Delivery

Copper may be delivered against the high-grade copper contract only from a warehouse in the United States licensed or designated by the Exchange. Delivery must be made upon a domestic basis; import duties or import taxes, if any, must be paid by the seller, and shall be made without any allowance for freight.

Delivery Period

The first delivery day is the first business day of the delivery month; the last delivery day is the last business day of the delivery month.

Exchange of Futures for, or in Connection with, Physicals (EFP)

The buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position.

Grade and Quality Specifications

Grade 1 electrolytic copper conforming to the specification B115 as to chemical and physical requirements, as adopted by the American Society for Testing and Materials, and of a brand approved and listed by the Exchange.

Position Accountability Levels

Any one month/all months: 6,000 net futures equivalent, but not to exceed 2,500 in the spot month.

Margin Requirements

Margins are required for open futures and short options positions. The margin requirement for an options purchaser will never exceed the premium paid.

Trading Symbol

HG

C.5 COFFEE

New York Board of Trade Description and Specifications
Source: www.nybot.com
Futures Contract on Coffee "C"

Calls for delivery of washed arabica coffee produced in several Central and South American, Asian and African countries.

Trading Unit

37,500 lbs. (approximately 250 bags)

Trading Hours

9:00 a.m. - 11:45 a.m.; NY Time.

Price Quotation

Cents per pound

Delivery Months

March, May, July, September, December

Ticker Symbol

KC

Minimum Fluctuation

5/100 cent/lb., equivalent to $18.75 per contract.

Last Trading Day:

One business day prior to last notice day.

First Notice Day:

Seven business days prior to first business day of delivery month.

Last Notice Day:

Seven business days prior to last business day of delivery month.

Daily Price Limits:

None

Position Limits:

Spot Month: 500 contracts as of the first notice day in the expiring month. Additionally, Position Accountability Rules apply to all futures and options contract months. Contact the Exchange for more information.

Standards:

A Notice of Certification is issued based on testing the grade of the beans and by cup testing for flavor. The Exchange uses certain coffees to establish the "basis" coffees judged better are at a premium those judged inferior are at a discount.

Deliverable Growths: Country Differential

Mexico, Salvador, Guatemala, Costa Rica, Nicaragua, Kenya, New Guinea, Panama, Tanzania, Uganda Basis

Colombia Plus 200 pts

Honduras, Venezuela, Peru Minus 100 pts

Burundi, India, Rwanda Minus 300 pts

Dominican Republic, Ecuador Minus 400 pts

Delivery Points:

Exchange licensed warehouses in the Port of New York District (at par), the Port of New Orleans, the Port of Bremen/Hamburg[1] , the Port of Antwerp[1] , and the Port of Miami (at a discount of 1.25 cents/lb).

[1] The Ports of Bremen/Hamburg and Antwerp are effective commencing with the Dec. 2002 delivery.

D

APPENDIX D: DEREGULATION AND THE EVOLUTION OF PRICING STRATEGY

This appendix summarizes the deregulation of the telecommunications industry with respect to the impact on wholesale and consumer prices.

Wholesale Prices

The Telecommunication Act of 1996 required RBOCs to open their monopolized markets to competition by providing interconnection to new entrants. The RBOCs were required to provide unbundled network elements to competitors on a wholesale basis, giving competitors the ability to provide the network services to consumers under a different brand name.

This system is still tightly regulated to ensure a competitive environment. The Federal Communications Commission (FCC) and the state utility commissions utilize a pricing methodology that prices network elements using "forward looking long–run incremental cost pricing principles."[1] This approach is designed to simulate the price that would have been in effect if there were full competition and if the market were able to get the most efficient and cheapest means of service currently available. RBOCs are still fighting this, claiming that they originally made investments in universal telecommunications technologies based on monopoly protection and they should be compensated for this before the rules are changed.

Consumer Prices: Local Service

The Telecom Act of 1996 was designed to force the baby Bells to give up their monopolies on local services and to open these markets to other competitors selling local and tolling services. The Act was also intended to position competitors to provide other value-added services in the future. Other telecommunications companies, cable companies, broadcasters, gas and electric utilities, and wireless services have entered the local services market. However, RBOCs still dominate local phone services and largely control the rollout of broadband access via digital service lines (DSL). Pricing of these services is still regulated.

State regulatory agencies oversee local rates, which vary greatly from area to area.[2] Pricing structures include flat rate, message-based and measured service plans. Flat rate service subscribers pay no additional fees for calls within their local calling area, regardless of the number of calls placed. Message services subscribers pay by call, regardless of the length of the

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1 Forward-looking cost methodology that postulates a hypothetical network based on near-term best practice technology and efficient engineering (Cave, p. 408).

2 Monitoring Report on Universal Service, FCC.

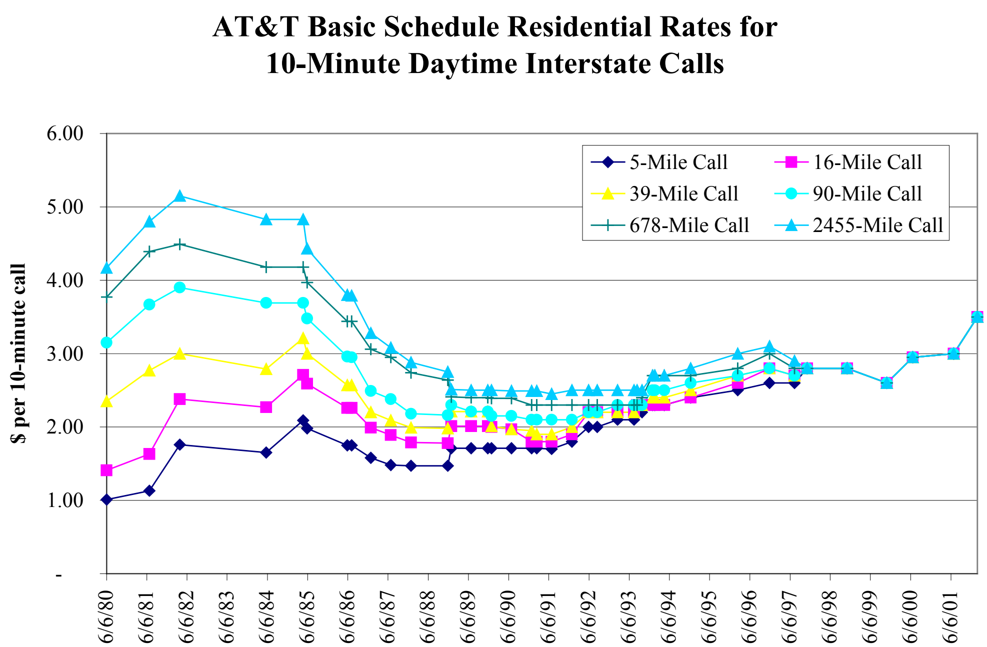
call. Measured service plans bill customers based on the length of the call. In addition to these fees, regulators authorize local carriers to levy other charges in order to give the carrier the opportunity to be fully compensated for the cost of providing services.

The emergence of competition in this segment of the telecom market has resulted in an increase in the number of calling plans and service packages available to consumers. Service providers are rebundling services to provide packages of communications services at attractive rates, rather than offering individually priced services.[3]

Consumer Prices: Long Distance

Historically, regulators have overseen long distance rate setting. AT&T was subject to rate of return regulation until 1989. This was replaced by price cap regulation that lasted until 1995, when direct price regulation in the industry ended.

Figure D-1



However, as indicated in Figure D-1, the cost of placing long distance calls has dropped dramatically since 1984. The three key reasons for this are as follows:

- First, the reduction of implicit subsidies from long distance providers to local service providers has contributed to the decrease in rates. During the divestiture in 1984, the FCC came up with a system of access charges, a uniform method for local companies to charge for

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3 Cave, p. 668.

the origination and termination of interstate traffic on their local networks. This permitted the reduction in implicit subsidies from long distance service to local service.

Introduction of monthly subscriber line charges allowed recovery of a portion of the fixed costs of the local telephone companies' loops directly from end users and long distance carriers (on a per line basis). This resulted in a reduction in the per-minute access price that long distance carriers pay, contributing to the reductions in long distance prices for end consumers. Initially, the combined originating and terminating access charges amounted to $0.17 per minute and represented almost half of the total toll revenue collected by interstate carriers. However, regulators gradually reduced these access charges to $0.095 in 1989 and to $0.019 at the end of 2000.[4]

- Second, competition among long-distance providers has forced long distance providers to be more efficient and to reduce costs in order to compete effectively in the market.

- Finally, competition has increased due to the number of substitute products that have been developed in the past few years. The increased use of wireless communication and data services such as email and the Internet have lowered dependence on traditional long distance phone service.

Table D-1 below shows the average revenue per minute for interstate calls. It shows that billed revenue per minute has declined over time for both international and domestic services.

Table D-1

Average Revenue per Minute for Interstate Phone Calls

Year	*Revenue per Minute*
1992	0.15
1993	0.15
1994	0.14
1995	0.12
1996	0.12
1997	0.11
1998	0.11
1999	0.11
2000	0.09

Source: Federal Communication Commission

4 Cave, p 61.

E

APPENDIX E: STATISTICAL RELATIONSHIP BETWEEN NATURAL GAS PRICES AND NATURAL GAS VOLATILITY

Table A-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

Figure A-1
Henry Hub Price and Price Volatility

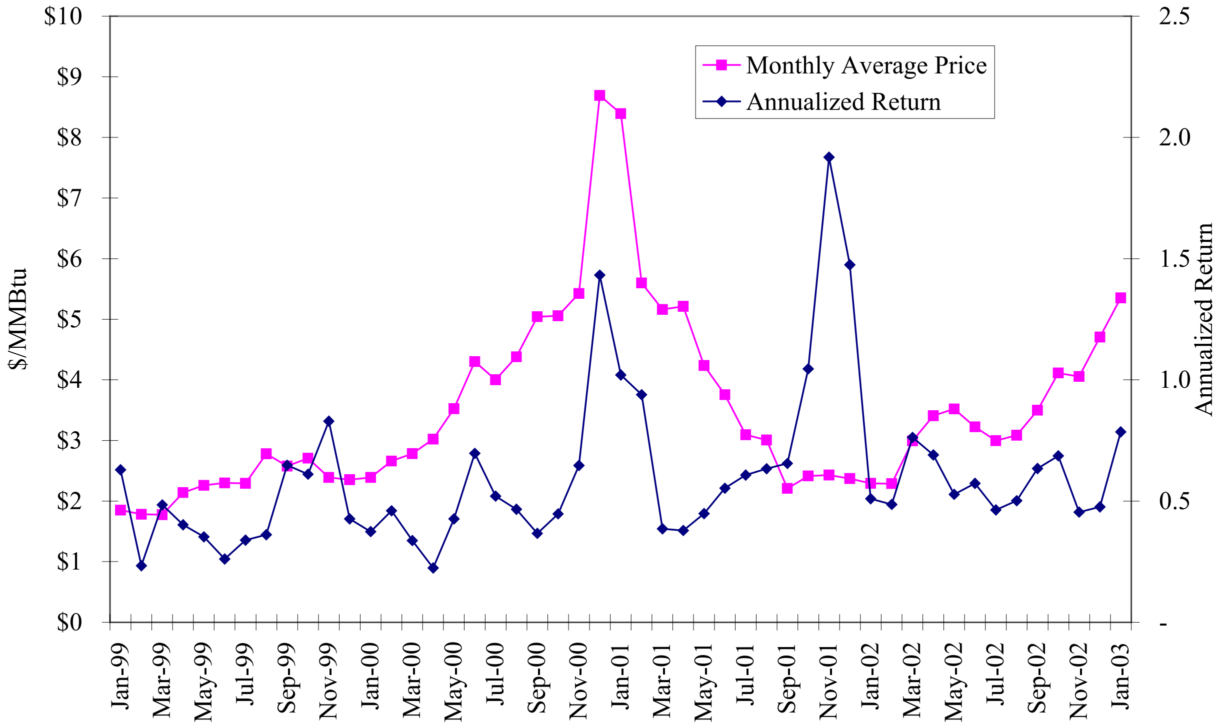


Table A-1
Relationship Between Natural Gas Prices and Price Volatility at Henry Hub

Regression Statistics	
Multiple R	0.806
R Square	0.650
Adjusted R Square	0.635
Standard Error	0.195
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	3.235	1.617	42.680	3.3026E-11
Residual	46	1.743	0.038		
Total	48	4.978			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.237	0.074	3.216	0.002	0.089	0.386	0.089	0.386
Monthly Average Price	0.086	0.019	4.547	0.000	0.048	0.125	0.048	0.125
Enron Collapse Dummy	1.034	0.118	8.757	0.000	0.797	1.272	0.797	1.272

Figure A-2
SoCal Price and Price Volatility

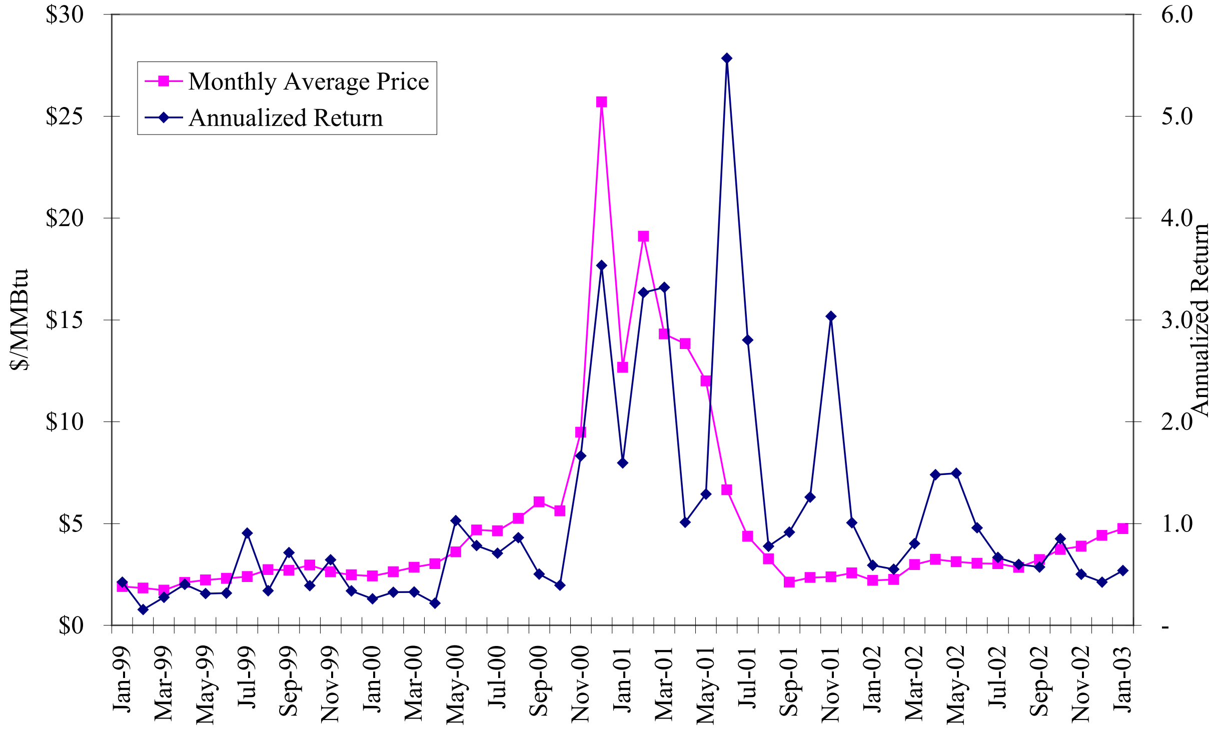


Table A-2
Relationship Between Natural Gas Prices and Price Volatility at SoCal Gas

Regression Statistics	
Multiple R	0.639
R Square	0.408
Adjusted R Square	0.383
Standard Error	0.844
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	22.619	11.309	15.872	5.7297E-06
Residual	46	32.777	0.713		
Total	48	55.395			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
	0.300	0.180	1.665	0.103	(0.063)	0.663	(0.063)	0.663
Monthly Average Price	0.139	0.026	5.429	0.000	0.087	0.190	0.087	0.190
Enron - variable	1.129	0.508	2.225	0.031	0.107	2.151	0.107	2.151

Figure A-3
PG&E City-gate Price and Price Volatility

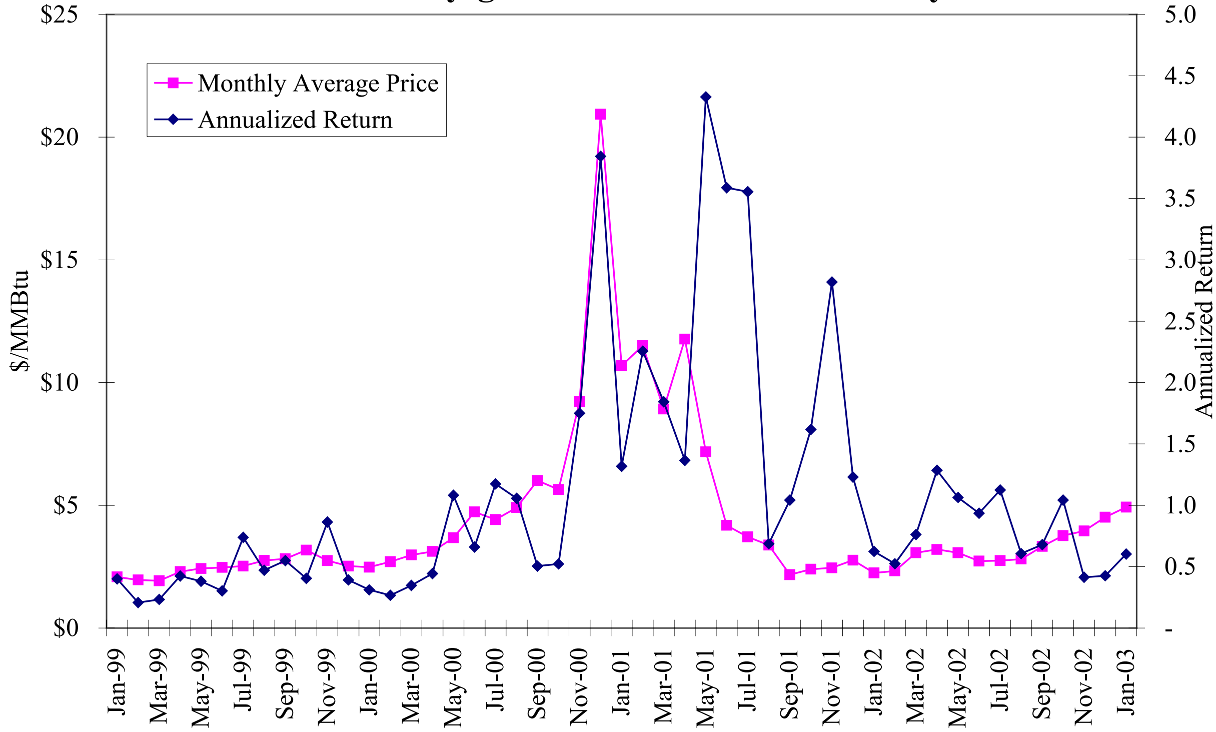


Table A-3
Relationship Between Natural Gas Prices and Price Volatility at PG&E Citygates

Regression Statistics	
Multiple R	0.612
R Square	0.374
Adjusted R Square	0.347
Standard Error	0.800
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	17.600	8.800	13.741	2.0954E-05
Residual	46	29.460	0.640		
Total	48	47.060			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.283	0.192	1.469	0.149	(0.104)	0.670	(0.104)	0.670
Monthly Average Price	0.166	0.034	4.923	0.000	0.098	0.234	0.098	0.234
Enron Collapse Dummy	1.185	0.481	2.461	0.018	0.216	2.154	0.216	2.154

Figure A-4
Chicago City-gate Price and Price Volatility

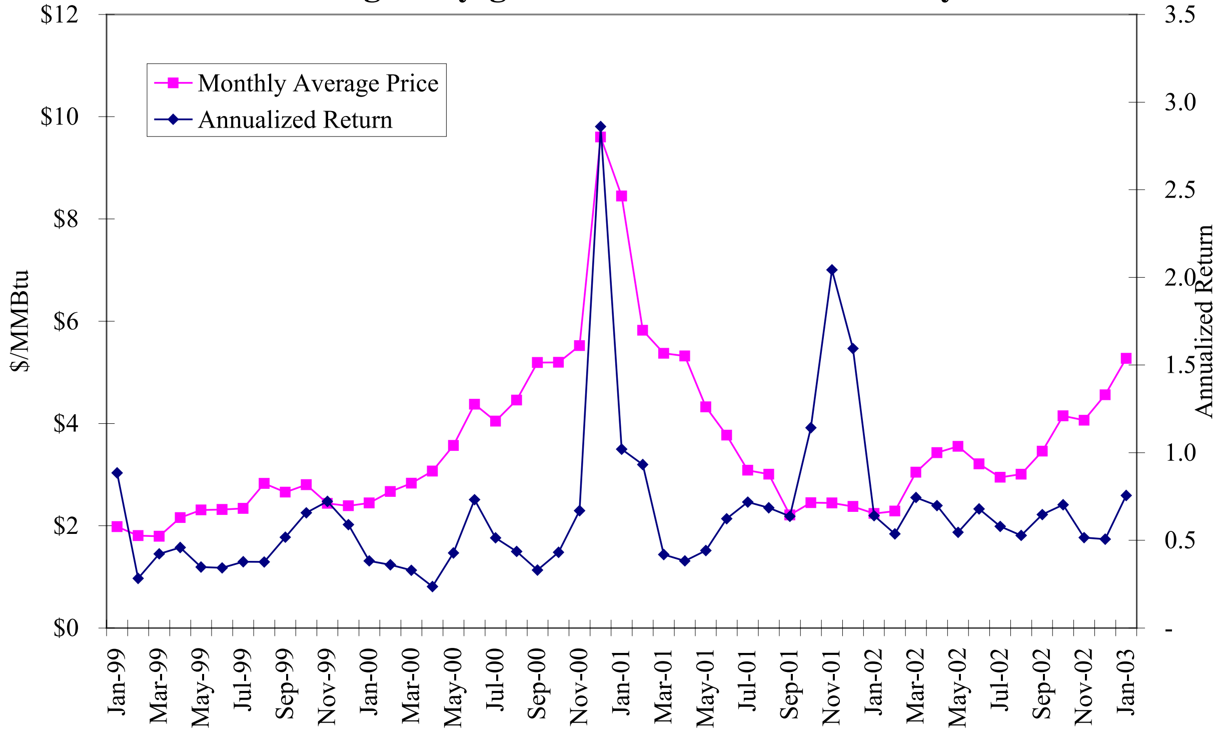


Table A-4
Relationship Between Natural Gas Prices and Price Volatility at Chicago Citygates

Regression Statistics	
Multiple R	0.740
R Square	0.547
Adjusted R Square	0.528
Standard Error	0.310
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.364	2.682	27.824	1.2027E-08
Residual	46	4.434	0.096		
Total	48	9.798			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.060	0.114	0.527	0.601	(0.169)	0.289	(0.169)	0.289
Monthly Average Price	0.149	0.029	5.180	0.000	0.091	0.206	0.091	0.206
Enron Collapse Dummy	1.174	0.188	6.234	0.000	0.795	1.553	0.795	1.553

Figure A-5
Transco Zone 6 - New York Price and Price Volatility

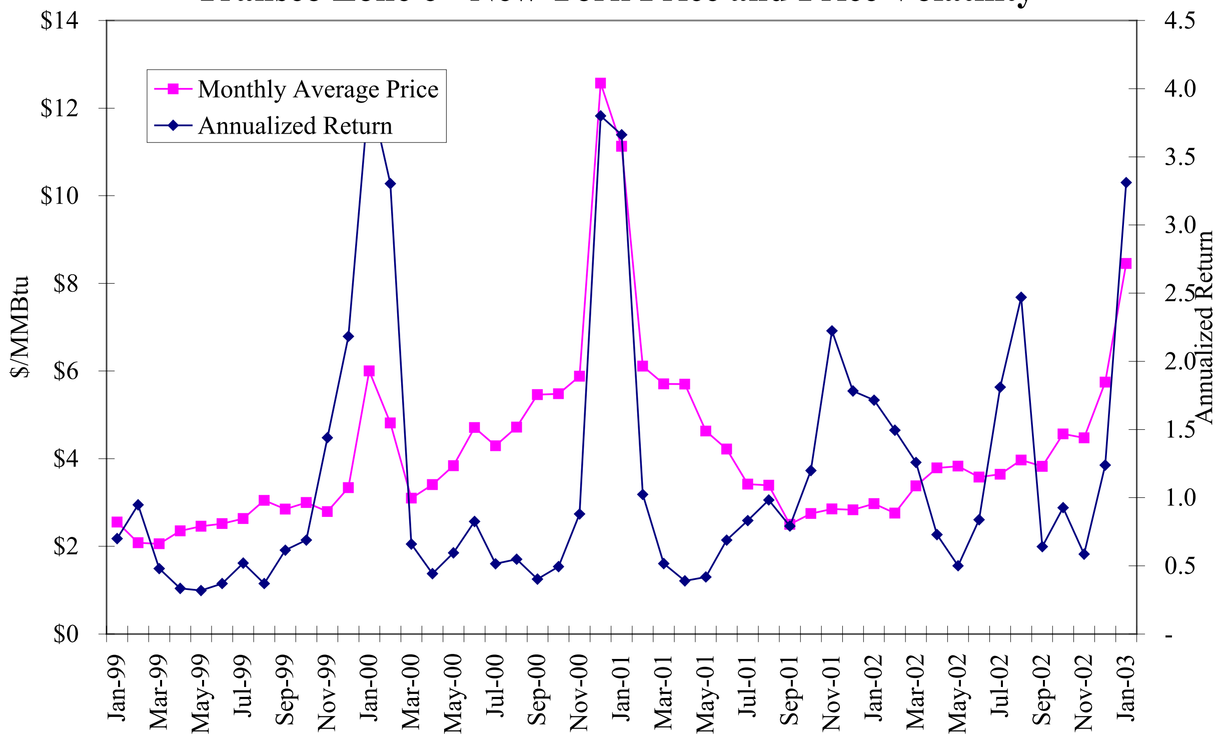


Table A-5
Relationship Between Natural Gas Prices and Price Volatility
at Transco Zone 6, New York

Regression Statistics	
Multiple R	0.637
R Square	0.406
Adjusted R Square	0.380
Standard Error	0.775
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	18.887	9.444	15.741	6.1932E-06
Residual	46	27.598	0.600		
Total	48	46.486			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	(0.152)	0.262	(0.579)	0.565	(0.679)	0.376	(0.679)	0.376
Monthly Average Price	0.299	0.055	5.459	0.000	0.189	0.410	0.189	0.410
Enron Collapse Dummy	1.044	0.469	2.228	0.031	0.101	1.988	0.101	1.988

Figure A-6
Katy Hub Price and Price Volatility

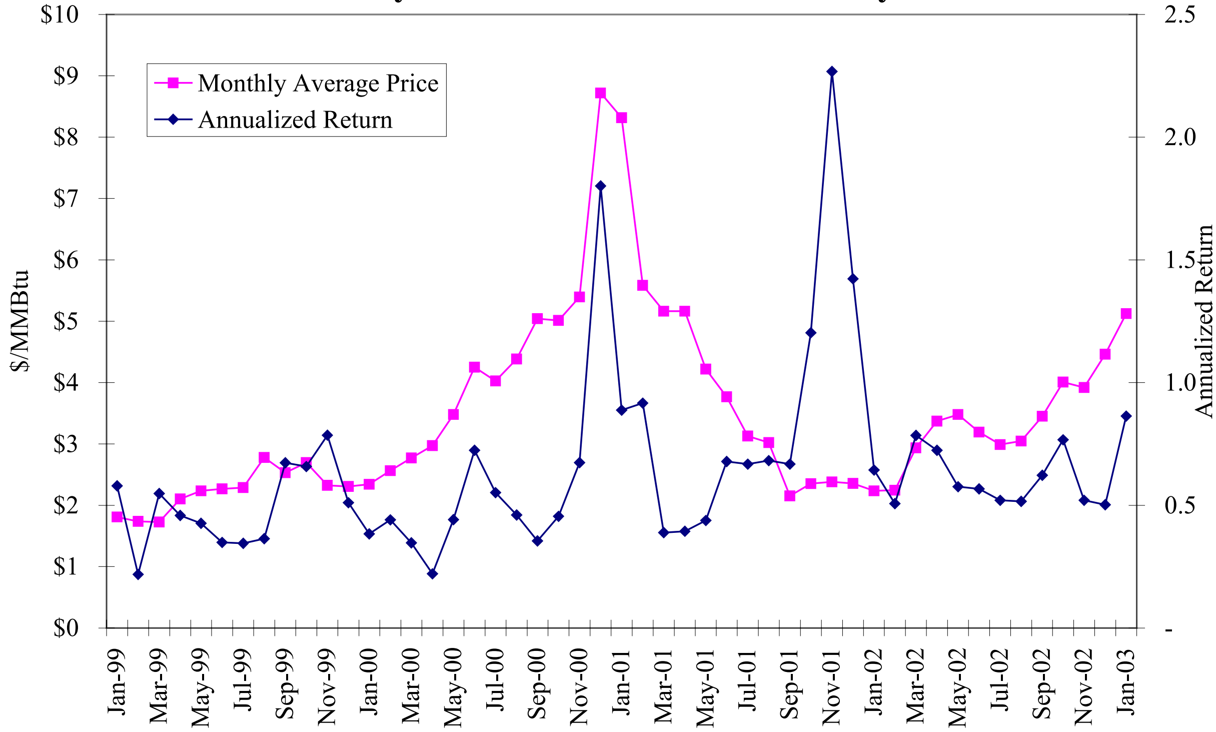


Table A-6
Relationship Between Natural Gas Prices and Price Volatility at Katy Hub

Regression Statistics	
Multiple R	0.787
R Square	0.620
Adjusted R Square	0.604
Standard Error	0.233
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.058	2.029	37.537	2.1537E-10
Residual	46	2.487	0.054		
Total	48	6.545			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.244	0.087	2.786	0.008	0.068	0.420	0.068	0.420
Monthly Average Price	0.095	0.023	4.162	0.000	0.049	0.140	0.049	0.140
Enron Collapse Dummy	1.164	0.141	8.250	0.000	0.880	1.448	0.880	1.448

Figure A-7
Columbia Gas, Appalachia Price and Price Volatility

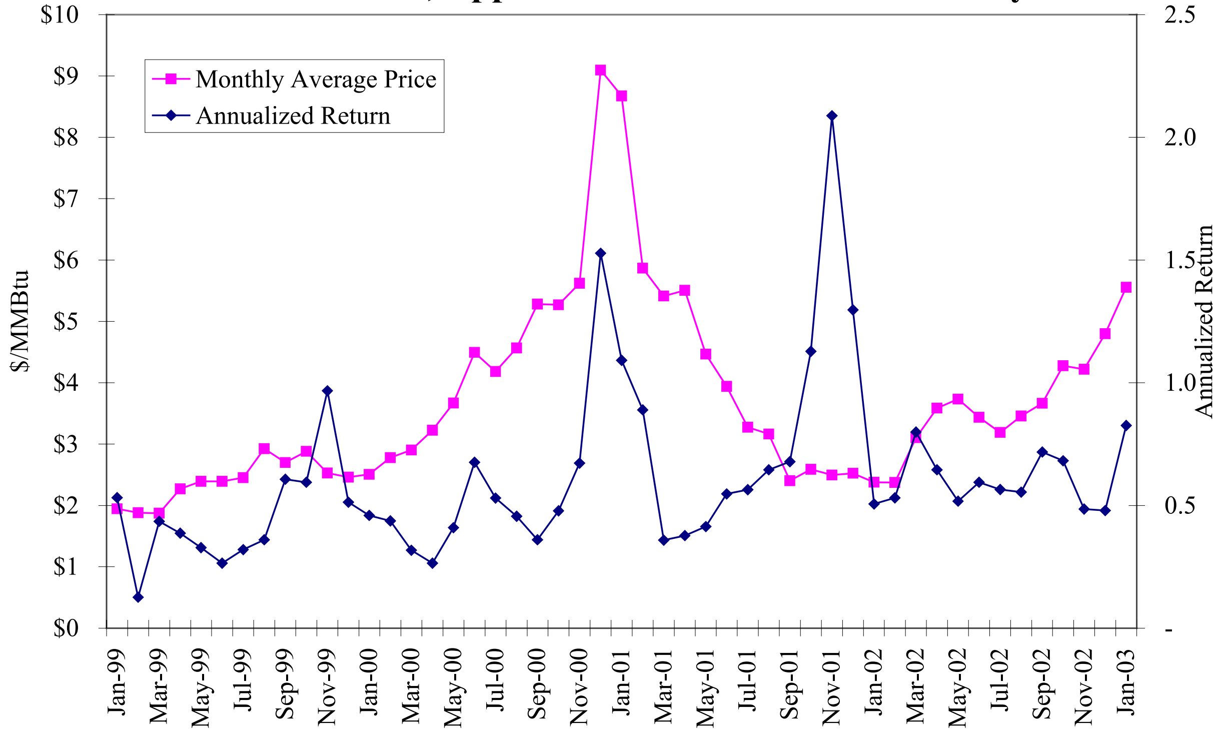


Table A-7
Relationship Between Natural Gas Prices and Price Volatility at Columbia, Appalachia

Regression Statistics	
Multiple R	0.786
R Square	0.617
Adjusted R Square	0.601
Standard Error	0.216
Observations	49

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	3.475	1.737	37.123	2.5228E-10
Residual	46	2.153	0.047		
Total	48	5.628			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.212	0.083	2.552	0.014	0.045	0.379	0.045	0.379
Monthly Average Price	0.091	0.020	4.460	0.000	0.050	0.132	0.050	0.132
Enron Collapse Dummy	1.062	0.131	8.085	0.000	0.797	1.326	0.797	1.326

F
APPENDIX F: USING FINANCIAL DERIVATIVE PRODUCTS TO HEDGE PRICES

Financial derivative products are contracts whose value are linked or "derived" from the value of an underlying commodity such as natural gas, oil, or electricity. The purpose of this appendix is to introduce a number of the products that are widely used in energy markets and to present some simple examples of how the products are used to hedge price risk and manage price volatility.

Financial derivatives can be sold either by an exchange, such as the New York Mercantile Exchange (NYMEX) or over the counter (OTC). In an exchange transaction, the exchange serves to balance the overall portfolio of contracts insuring that for every short position, there is a long position in exchange for a fee. In an OTC transaction, a "market maker" such as a large financial institution (e.g., Goldman Sachs, CityGroup, J P Morgan Chase, etc) manages their "business book." These entities can take a position themselves and are therefore subject to credit risk and can be subject to price risk to the extent that their "book" is not balanced. The large energy-marketing firms were important "market makers" prior to the Enron bankruptcy and the collapse of a number of other firms.

The objective of a hedge is to reduce the risk of price volatility. In a sense, when used as a hedge, a financial derivative is similar to an insurance policy. An insurance policy is a contract that provides for a cash payment if a specific (unfavorable) event occurs during the term of the policy. Financial derivatives can be used to reduce price risk by generating a cash payment in the event that the market price of the commodity moves in an unfavorable direction.

Every financial derivative specifies a "strike date." The strike date is the point in time when the contract must be settled and payment made. Every financial derivative also contains a price (or price formula) used to calculate the value of the contract at the time specified as the strike date. Finally, the derivative specifies the terms for the settlement of the contract that determines the relationship of the derivative to the commodity itself. For example, the NYMEX natural gas specifies the terms of settlement as 10,000 MMBtus of gas at Henry Hub in Louisiana delivered over a one-month period. The strike date for the contract is 3 business days ***prior*** to month of delivery. The commodity price is equal to the "market price" cleared by the exchange.

When "buying" a financial derivative, the party must pay a percentage of the "market" value of the derivative at the time of purchase. For energy and other non-currency derivatives, the percentage is generally between 10 and 20 percent. As a result, the party incurs the cost of the time value of the money committed. There is no interest paid on the "margin" payment required at the time that the party enters into the contract. Moreover, if the "market" price of the commodity changes, the party can be required to increase the "margin" or deposit on the contract.

Speculators to manage price risk also use these same products. A speculator's objective is to generate profits from the movement of prices in a commodity. The "leverage" provided by margin percentage to magnify the gains or losses of the speculator. The speculator must assume risk by taking an unbalanced position (short or long) in the hope that the commodity price moves in the direction that increases the value of the position.

Futures Contract Example

In March, the futures price for gas delivered in January $5.60. Party A expects to need gas in January and wants to make sure that they do not have to pay more than $5.60. Party A buys a contract for January gas at $5.60 to lock in the price.

As the strike date approaches in late January, the futures price should – and usually does – converge towards the bidweek prices. If in January, the bidweek price for gas at Henry Hub is $6.15, the purchaser buys physical gas for January for $6.15 and sells the future contract back at the prevailing future market price, around $6.15 per MMBtu. Party A has a gain of $.55 per MMBtu on the future transaction. The gain on the futures contract offsets the fact that Party A was forced to buy gas at $6.15 per MMBtu. When the cost of the gas is combined with the "gain" on the future contract, the "net" gas cost is $5.60 per MMBtu, which was the locked in price.

If, however, the bidweek price for January gas is $5.25 per MMBtu, the purchaser will buy their gas for $5.25 and take a $.35 loss on the futures contract. Nevertheless, the "net" cost January gas remains $5.60 per MMBtu because the loss is "offset" by the fact that Party A can buy the gas at the lower price.

Commodity Swap Example

A Swap contract between two parties in the market. Generally an OTC "market maker" offers swaps although any two parties could enter into such an agreement. A swap differs from a futures contract in that it specifies "marker" price that does not vary during the term of the contract. The contract obligates the parties to make payment equal to the difference between the cash price and the "trigger" price. If the cash price is above the "trigger" price, the seller of the swap pays the buyer, if the cash price is below the "trigger," buyer pays the seller.

Since the terms of settlement can be negotiated between the parties, a market maker can offer an almost infinite variety of swaps. For natural gas swaps, it is particularly valuable to commercial interests to be able to enter in swap at specific the location along the gas pipeline system, i.e., interconnects, citygates, and pipeline receipt and delivery points.

Assume that Party A wants to lock in a $4.00 price for gas at Transco station 65 over the next 3 months, so "A" signs a swap agreement with a market maker.

Over the three-month period, the index price averages $4.25 per MMBtu. The purchaser buys the physical gas at the index price of $4.25 and is paid $.25 under the swap for a "net" gas cost $4.00. If however the price averages $3.70 per MMBtu, the purchaser buys at index price but has to pay $.30 to the market maker under the terms of the swap. The net gas cost remains $4.00 per MMBtu.

Collar Example

A "collar" is similar to a swap but specifies a "dead band" of prices rather than a specific "market price." Under the terms of the collar, no payment is made when the index price falls within the dead band. A payment is made when the cash price falls outside the "dead band" based upon the difference in the index price and the limit of the dead band. The market maker charges an origination fee for the collar.

In this case, Party A wanting to insure against a large price increase, buys a three-month collar at $4.00 per MMBtu with a $.15 cent spread around the $4.00 price. If the cash price is between $3.85 and $4.15, no payment is made on the collar. Over the three-month period, the index price for physical gas averages $4.25 per MMBtu. The purchaser buys the gas at index, but is paid $.10 under the collar for a net cost of gas of $4.15. If the index price averages $3.70, the purchaser buys at index but has to pay $.15 under the collar for a net cost of gas of $3.85. If the average of index price over the three-month period falls between $3.85 and $4.15, no payment is made for the collar.

A common variant is a so-called "costless collar." Because the market maker recognizes that the prices tend to move by larger absolute values in an upward direction that they move in a downward direction, the market maker will offer a collar that has an dead band that is asymmetric around the price that the market expects. For example, if the NYMEX futures price for gas next December was $6.00, the market maker might sell a collar banded from $5.80 to $7.00 providing some insurance to the buyer against large price spikes.

The term "costless" collar is a misnomer because the buyer pays a fee to the market maker. The size of the fee can change depending upon the market conditions, but the cost of the example presented above would generally be below $0.50.

Options

An option provides "insurance" for price movements in one particular direction. The options give the holder the right, but not the obligation, to buy or sell at a "strike price." If a gas buyer wants to insure that the gas price does not rise beyond a certain limit, the buyer pays the market maker for a "Call." The Call gives the buyer the right to buy at the "strike price." Similarly, if a gas producer wants to establish a minimum price for its production, the producer pays the market maker for a "Put." The Put give the gas producer the right to sell gas at the "strike price."

Options are much more expensive than swaps or futures because the option does not obligate the buyer of the option to the strike price. Rather, the buyer can choose whether or not to exercise the right that is conveyed by the option. As a result, the buyer of the option does not forgo the benefit that occurs if the price of the commodity moves in a favorable direction, but does so at an increased cost.

In this case, Party A buys a May "call" with a $5.10 per MMBtu "strike price" for $0.26 to insure against a big price increase. If the May price is $5.50 per MMBtu, the value of the option is $.40. Party A can sell the option at the strike date for a net gain of $.14. Party A would then buy the physical gas at the market price of $5.50 for a net gas cost of $4.36.

If however, the May price is $6.00, the value of the option is $.90. When Part A sells the option, a net gain of $.64 is obtained. Party A would then buy the physical gas at the market price $6.00 for a net cost of $4.36.

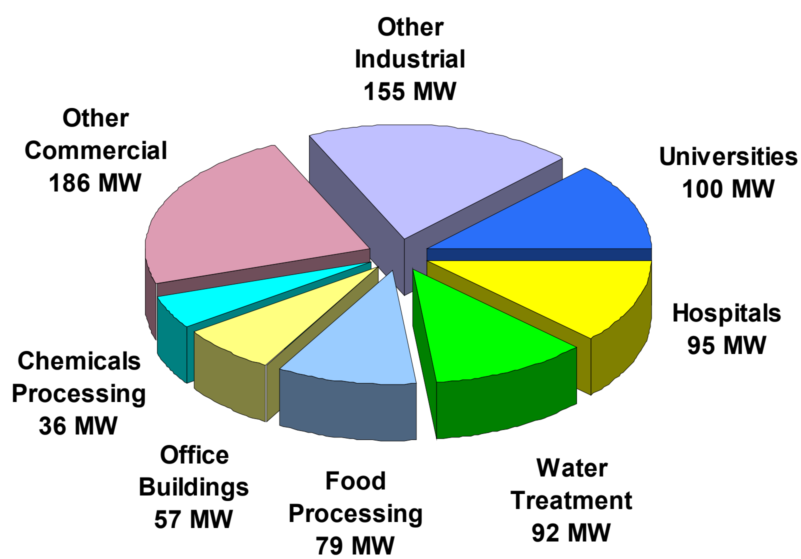
But if the May price drops to $4.00 per MMBtu, the value of the option is zero and Party A loses the entire initial cost of the option for a net loss of $.26. Party A would then buy the physical gas at the market price $4.00 for a net cost of $4.26 which is well below the strike price of the option.

G
APPENDIX G: INSTALLED CHP

Reciprocating Engine CHP

There were an estimated 1,055 engine-based CHP systems operating in the United States in 2000 representing over 800 MW of electric capacity. Facility capacities range from 30 kW to 30 MW, with many larger facilities comprised of multiple units. Reciprocating engine CHP is installed in a variety of applications as shown in Figure 1. Spark ignited engines fueled by natural gas or other gaseous fuels represent 84% of the installed reciprocating engine CHP capacity.

Figure 1
Existing Reciprocating Engine CHP - 801 MW at 1,055 sites

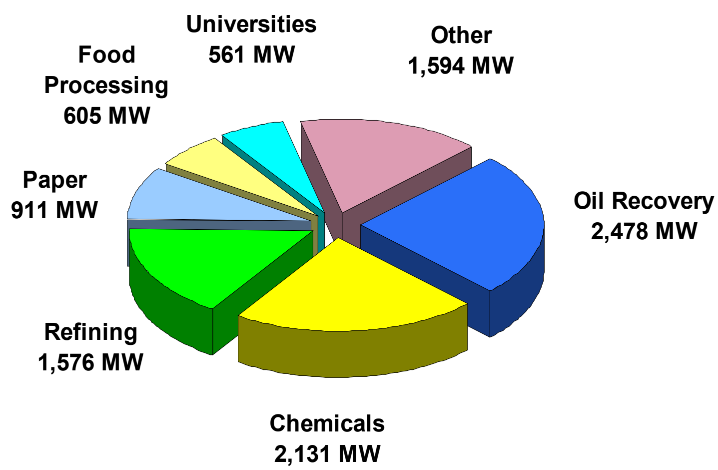


Source: ***Energy and Environmental Analysis/Energy Nexus Group, Hagler Bailly Independent Power Database.***

Gas Turbine-Based CHP

There were an estimated 40,000 MW of gas turbine-based CHP capacity operating in the United States in 2000 located at over 575 industrial and institutional facilities. Much of this capacity is concentrated in large combined cycle CHP systems that maximize power production for sale to the grid by generating additional power from steam turbines before sending the steam to internal process needs or to heat the facility. However, a significant number of simple cycle gas turbine-based CHP systems are in operation at a variety of applications as shown in Figure 2. Simple cycle CHP applications are most prevalent in smaller installations typically less than 40 MW.

Figure 2
Existing Simple Cycle Gas Turbine CHP – 9,854 MW at 359 sites

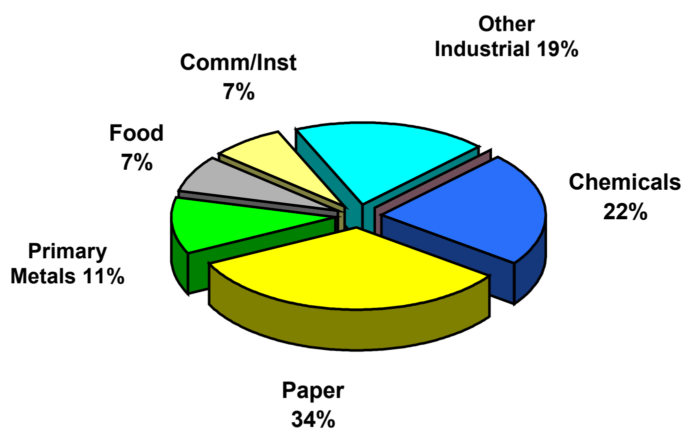


Source: Energy and Environmental Analysis/Energy Nexus Group, Hagler Bailly Independent Power Database.

Boiler/Steam Turbine CHP

There were an estimated 19,062 MW of boiler/steam turbine CHP capacity operating in the United States in 2000 located at over 580 industrial and institutional facilities. As shown in Figure 3, the largest amounts of capacity are found in the chemicals, primary metals, and paper industries. Pulp and paper mills are often an ideal industrial/CHP application for steam turbines. Such facilities operate continuously, have a very high demand for steam, and have on-site fuel supply at low, or even negative costs (waste that would have to be otherwise disposed of).

Figure 3 – Existing Boiler/Steam Turbine CHP Capacity by Industry
19,062 MW at 582 Sites



Source: Energy and Environmental Analysis/Energy Nexus Group, Hagler Bailly Independent Power Database

H
APPENDIX H: DG/CHP TECHNOLOGY CHARACTERISTICS

Reciprocating Engines

The features that have made reciprocating engines a leading prime mover for CHP and other distributed generation applications include:

Size range:	Reciprocating engines are available in sizes from 10 kW to over 5 MW, and can be matched to the electric demand of many end-users (institutional, commercial and industrial).
Thermal output:	Reciprocating engines can produce hot water and low pressure steam for a variety of combined heat and power applications.
Fast start-up:	In peaking or emergency power applications, reciprocating engines can quickly supply electricity on demand. The fast start-up capability of reciprocating engines allows timely resumption of the system following a maintenance procedure.
Black-start capability:	In the event of a electric utility outage, reciprocating engines can be started with minimal auxiliary power requirements. Generally only batteries are required.
Availability:	Reciprocating engines have typically demonstrated availability in excess of 95% in stationary power generation applications.
Part-load operation:	The high part-load efficiency of reciprocating engines ensures economical operation in electric load following applications.
Reliability and life:	Reciprocating engines have proven to be reliable power generators given proper maintenance.
Emissions:	Diesel engines have relatively high emissions levels of NO_x and particulates. However, natural gas spark ignition engines have improved emissions profiles and can be sited in most non-attainment areas.

Small Gas Turbines

Gas turbine features may be summarized as follows:

Thermal output:	Gas turbines produce a high quality (high temperature) thermal output suitable for most combined heat and power applications. High-pressure steam can be generated or the exhaust can be used directly for process drying and heating.
Fuel flexibility:	Gas turbines operate on natural gas, synthetic gas, landfill gas and fuel oils. Plants are often designed to operate on gaseous fuel with a stored liquid fuel for backup to obtain the less expensive interruptible rate for natural gas. Dual-fuel combustion capability is a purchase option on many gas turbines.
Reliability and life:	Modern gas turbines have proven to be reliable power generators if maintained properly. Time to overhaul is typically 25,000 to 50,000 hours.
Size range:	Gas turbines are available in sizes from 500 kW to 250 MW, and can be selected to match nearly any end-user electric demand.
Part Load Operation:	Because gas turbines reduce power output by reducing combustion temperature, efficiency at part load can be substantially below that of full power efficiency (i.e., 20 % lower efficiency at 50 % load).
Emissions:	Many small gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x combustors) that produce NO_x emissions below 25 ppm, with laboratory data down to 9 ppm, and simultaneous low CO emissions acceptable to regulators and safety personnel in the 50 to 10 ppm range.[1] Further reductions in NO_x and CO can be achieved by use of selective catalytic reduction (SCR) or catalytic combustion. Many gas turbines sited in locales with extremely stringent emission regulations use SCR after-treatment to achieve single-digit (below 9 ppm) NO_x emissions.

[1] Gas turbines have high oxygen content in their exhaust because they burn fuel with high excess air to limit combustion temperatures to levels that the turbine blades, combustion chamber and transition section can handle without compromising system life. Consequently, emissions from gas turbines are evaluated at a reference condition of 15% oxygen. For comparison, boilers use 3% oxygen as the reference condition for emissions, because they can minimize excess air and thus waste less heat in their stack exhaust. Note that due to the different amount of diluent gases in the combustion products, the mass of NO_x measured as 9 ppm @ 15% oxygen is approximately 27 ppm @ 3% oxygen, the condition used for boiler NO_x regulations.

Steam Turbines

Custom design:	Steam turbines can be designed to match various design pressure and temperature requirements. The steam turbine can be designed to maximize electric efficiency while providing the desired thermal output.
Thermal output:	Steam turbines are capable of operating over a very broad range of steam pressures. Utility steam turbines operate with inlet steam pressures up to 3500 psig and exhaust vacuum conditions as low as one inch of Hg (absolute). Steam turbines can be custom designed to meet the thermal requirements of the CHP applications through use of backpressure or extraction steam at appropriate pressures and temperatures.
Fuel flexibility:	Steam turbines offer a wide range of fuel flexibility using a steam generated in a boiler by combustion of a variety of fuels, including coal, oil, natural gas, wood and waste products.
Reliability and life:	Steam turbine life is extremely long. There are steam turbines that have been in service for over 50 years. Overhaul intervals are measured in years. When properly operated and maintained (including proper control of boiler water chemistry), steam turbines are extremely reliable. They require controlled thermal transients as the massive casing heats up slowly and differential expansion of the parts must be minimized.
Size range:	Industrial steam turbines are available in sizes from under 100 kW to over 250 MW. In the multi-megawatt size range, industrial and utility steam turbine designations merge, with the same turbine (high pressure) section able to serve both industrial and small utility applications.
Emissions:	Emissions are dependent upon the fuel used by the boiler or other steam source, boiler furnace combustion section design and operation, and built-in and add-on boiler exhaust cleanup systems.
Efficiency:	The electrical generating cycle efficiency of steam turbine power plants varies from a high of over 36% HHV[2] for large, electric utility plants designed for the highest practical annual capacity factor, to under 10% HHV for small, simple plants that make electricity as a byproduct of delivering steam to industrial processes or district heating systems for colleges, industrial parks and building complexes.

[2] Steam turbine power plants traditionally measure efficiency on a higher heating value (HHV) basis, while gas turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. The usable energy content of fuels is typically measured on a HHV basis. Electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content of natural gas is 1,030 Btu/scf on an HHV basis and 930 Btu/scf on an LHV basis – or about a 10% difference. The difference between the HHV and LHV is the heat of condensation of the water vapor in the combustion products.

Microturbines

Summary characteristics of microturbines are:

Thermal output:	Microturbines produce thermal output at temperatures in the 400 to 600° F range, suitable for supplying a variety of building thermal needs.
Fuel flexibility:	Microturbines can operate using a number of different fuels: natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/heating oil.
Reliability and life:	Design life is estimated to be in the 40,000 to 80,000 hour range. While units have demonstrated reliability, they have not been in commercial service long enough to provide definitive life data.
Size range:	Microturbines available and under development are sized from 30 to 350 kW.
Modularity:	Units may be connected in parallel to serve larger loads and provide power reliability.
Part-load operation:	Because microturbines reduce power output by reducing mass flow and combustion temperature, efficiency at part load can be below that of full-power efficiency.
Dimensions:	At about 12 cubic feet, microturbines are very compact.
Emissions:	Low inlet temperatures and high fuel-to-air ratios result in NO_x emissions of less than 10 parts per million (ppm) when running on natural gas.

Fuel Cells

Fuel cell systems are composed of three primary subsystems: 1) a fuel cell stack that generates direct current electricity; 2) a fuel processor that converts the natural gas into a hydrogen-rich feed stream (this can be integrated into the fuel cell stack in certain fuel cell configurations); and 3) a power conditioner that processes the electric energy into alternating current or regulated direct current. All systems run on hydrogen, which is most commonly derived by reforming natural gas.

There are five types of fuel cells currently under development. These are: 1) phosphoric acid (PAFC), 2) proton exchange membrane (PEMFC) – often referred to as a polymer electrolyte membrane cell, 3) molten carbonate (MCFC), 4) solid oxide (SOFC), and 5) alkaline (AFC). Each type is distinguished by the electrolyte used and by operating temperatures. Operating temperatures range from near-ambient to 1,800° F.

The features that have the potential to make fuel cell systems a leading prime mover for CHP and other distributed generation applications include:

Size range:	Fuel cell systems are constructed from individual cells that generate 100 W to 2 kW per cell. This allows systems to be configured in a wide range of capacities. Systems under development for DG application range in sizes from 5 kW to 2 MW. Multiple systems can operate in parallel at a single site to provide higher capacities.
Thermal output:	Fuel cells can achieve overall efficiencies in the 65 to 85% range. Waste heat can be used primarily for domestic hot water applications and space heating.
Availability:	The commercially available 200 kW PC25 system fleet (200-plus units) has demonstrated greater than 90% availability during over four million operating hours. As fuel cell systems mature, their reliability is expected to improve.
Part-load operation:	Fuel cell stack efficiency improves at lower loads, which results in a system electric efficiency that is relatively steady down to one-third to one-quarter of rated capacity. This provides systems with excellent load following characteristics.
Cycling:	While part load efficiencies of fuel cells are generally high, MCFC and SOFC fuel cells require long heat-up and cool-down periods, restricting their ability to operate in many cyclic applications.

High quality power:	Electrical output is computer grade power, meeting critical power requirements without interruption. This minimizes lost productivity, lost revenues, product loss or opportunity cost.
Reliability and life:	Since only auxiliary components have moving parts, the reliability of fuel cells is expected to be high. A few of the initial PC25 systems have achieved operational lives of 70,000 hours.
Efficiency:	Different types of fuel cells have varied efficiencies. Depending on the type and design of fuel cells, efficiency ranges from 30% to over 50% HHV.
Quiet Operation:	Conversational level (60dBA @ 30 ft.), acceptable for indoor installation.
Siting and Size:	Indoor or outdoor installation.
Fuel Use:	The primary fuel source for the fuel cell is hydrogen, which can be obtained from natural gas, coal gas, methanol, and other fuels, such as biomass, containing hydrocarbons.
Emissions:	The only combustion within a fuel cell system is the low energy content hydrogen stream exhausted from the stack. This stream is combusted within the reformer and can achieve emissions signatures of < 2 ppmv CO, <1 ppmv NO_x and negligible SO_x (on 15% O_2, dry basis).