

# *The Brattle Group*

---



## **Managing Natural Gas Price Volatility: Principles and Practices Across the Industry**

November 2010

Frank C. Graves  
Steven H. Levine

**Prepared for**

---



American Clean Skies Foundation

## Table of Contents

I.	Introduction: Some recent history and properties of gas markets.....	1
II.	Gas Market Risk Characteristics.....	8
	Variability vs. Volatility .....	8
	Price volatility vs. Returns volatility .....	8
	Gas markets and available hedging contracts .....	10
	Forward Price Risk Premiums .....	13
	Volatility term structure.....	13
	Mean reversion.....	14
III.	Risk management principles .....	16
IV.	Tools for managing natural gas price volatility .....	22
	Physical Tools.....	22
	Financial Tools.....	24
	Non-standard Contracts .....	30
V.	Risk Management Processes and Controls .....	32
	Goals .....	32
	Targets/Schedules .....	32
	Metrics/Reports.....	34
	Controls.....	34
	Limitations in managing gas price volatility .....	37
VI.	Comparisons of Industry Hedging Practices.....	41
	Gas Distribution Utilities - hedging for customers with physicals and financials.....	41
	Electric Utilities - hedging complex load for gas-fired generation.....	43
	Gas Producers - hedging to protect drilling economics and cash flow.....	45
	Major Integrated Gas Producer .....	45
	Mid-Size, Independent Gas Producers.....	46
	Industrial End-users – hedging gas used for feedstock and energy supply given constraints on final product prices .....	48
VII.	Conclusions and Recommendations .....	52

## I. INTRODUCTION: SOME RECENT HISTORY AND PROPERTIES OF GAS MARKETS

The volatility in natural gas prices over the course of the past 10 years has resulted in an increased emphasis on risk management activities by industry participants. Several major price spikes occurred during the decade, and a general tightening of the supply-demand balance in U.S. gas markets resulted in higher natural gas prices and higher price volatility for U.S. gas consumers relative to the experience of the 1990s. Some have suggested that speculation also contributed to high price levels and volatility – though there is no general agreement on this view.<sup>1</sup> Since natural gas is also the marginal or price-setting fuel in electricity markets in many regions of the country, the volatility in natural gas prices over the past decade also had a pronounced impact on retail electricity prices, and probably vice versa as well, since natural gas-fired generation has been the predominant source of increased gas demand over the past 15 years.

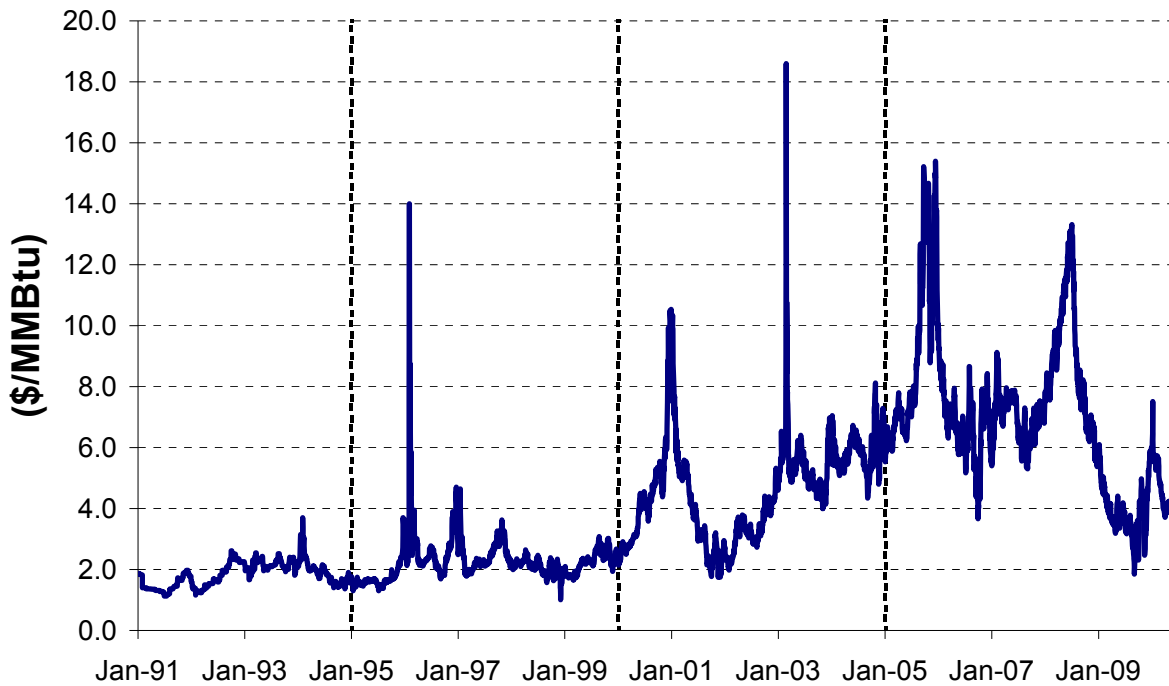
Figure 1 below shows the daily gas price at Henry Hub over the past 20 years.

---

<sup>1</sup> For example, see United States Senate Permanent Subcommittee on Investigations of the Committee on Homeland Security and Governmental Affairs, “Staff Report,” *Excessive Speculation in the Natural Gas Market*, June 25, 2007. The report found that a hedge fund, Amaranth Advisors LLC, dominated the U.S. natural gas market in 2006 and that its 2006 positions in the natural gas market constituted excessive speculation. See also, Written Testimony of Jeffrey Harris and John Fenton Before the Subcommittee on General Farm Commodities and Risk Management, Committee on Agriculture. Mr. Harris and Mr. Fenton analyzed the role of investors (both hedgers and speculators) in both energy and agriculture future markets and found that “there is little economic evidence to demonstrate that prices are being systematically driven by speculators in these markets.” They also found “the economic data shows that overall commodity price levels, including agriculture commodity and energy futures prices, are being driven by powerful fundamental economic forces and the laws of supply and demand.”

Figure 1

## Henry Hub Spot Price (1991-2010)



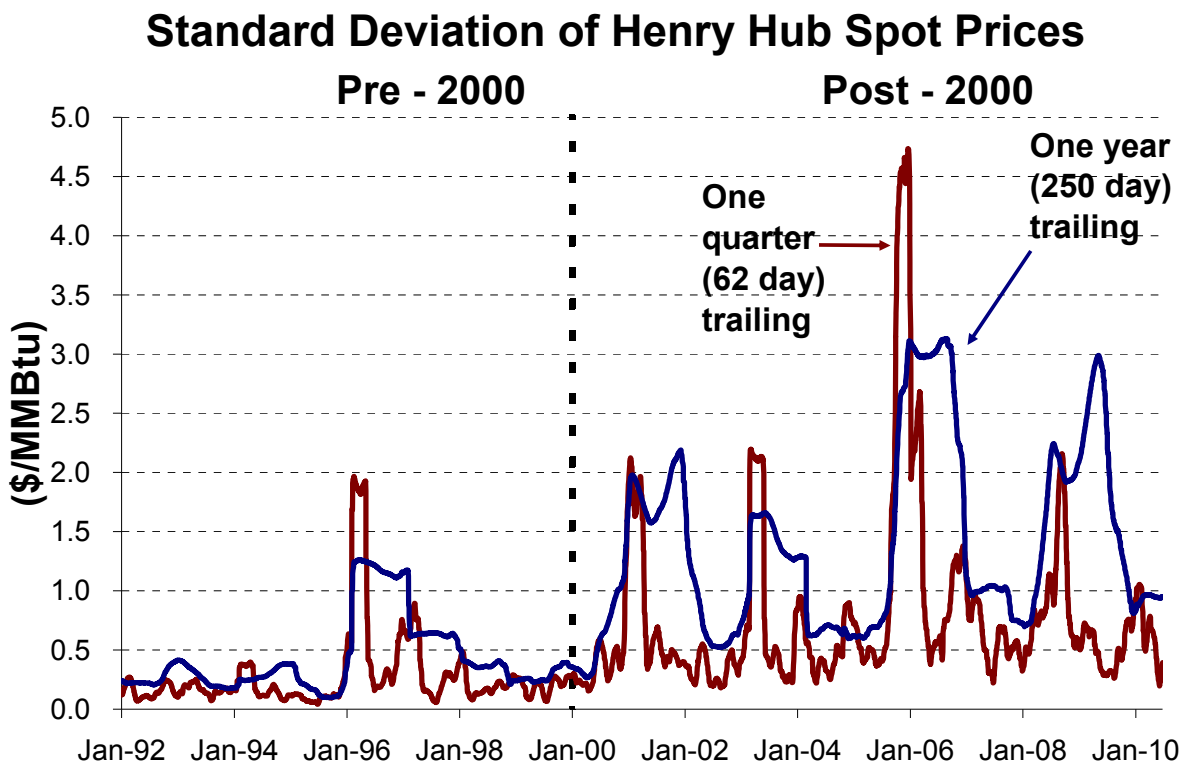
Source: Platts, Gas Daily.

It is immediately evident in this graph that most of the 1990s was a period of relatively stable prices, except for one significant price spike in 1996.<sup>2</sup> In contrast, the recent past decade was much more volatile and had several significant price spikes, the first occurring in the winter of 2000-2001, with additional price spikes in 2003 and in the fall of 2005 – the latter caused by major disruptions to U.S. gas markets due to hurricanes Katrina and Rita in August and September. Prices spiked again in the summer of 2008 (coinciding with a major spike in crude oil prices), but would collapse thereafter as new sources of unconventional supplies—especially shale supplies—started to serve U.S. gas markets in large quantities at the same time as the economic crisis resulted in a significant loss of industrial demand for natural gas.

The intuition from these graphs that gas prices have become not just higher but more variable as well is confirmed in Figure 2, which plots the 250-day and 90-day trailing standard deviation of daily Henry Hub prices.

<sup>2</sup> As discussed later, this period of low volatility in the 1990s may have been an artifact of prior gas supply regulatory policies.

Figure 2

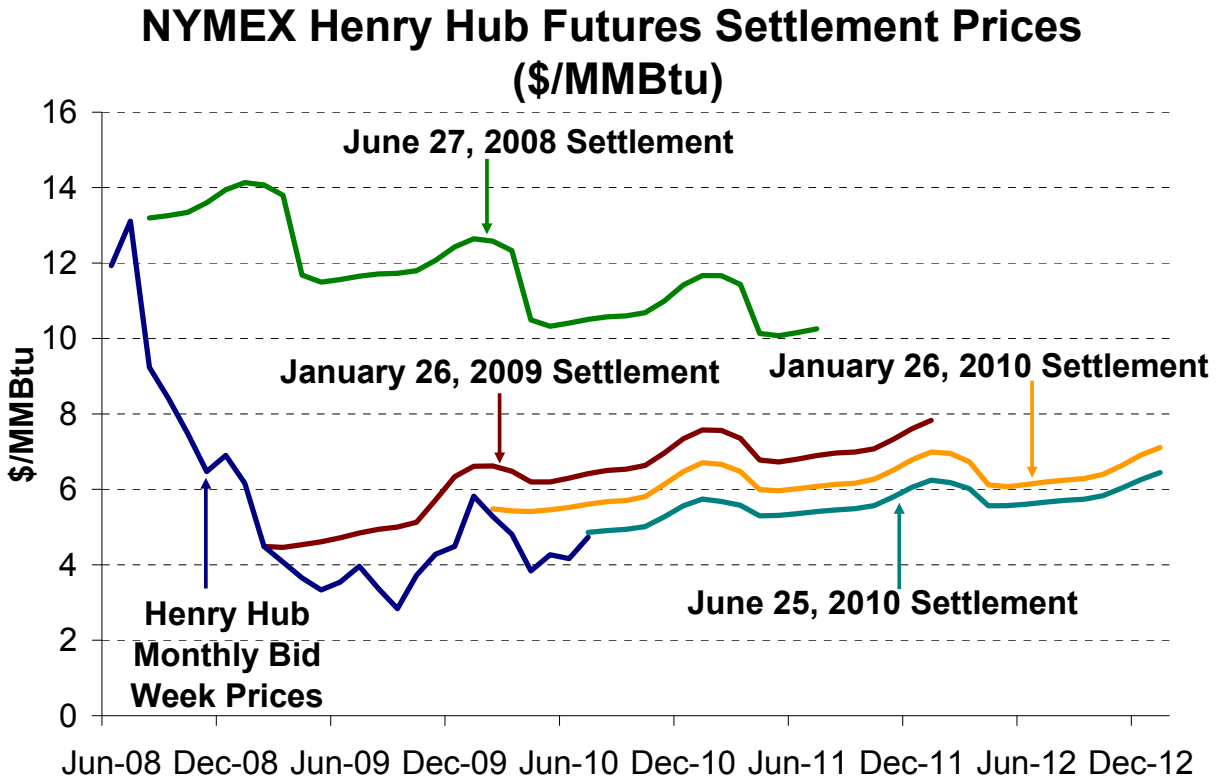


Source: Platts, Gas Daily.

Recall from introductory statistics classes that if the population of possible outcomes is normally distributed, then about 2/3 of observations should lie within one standard deviation on either side of the mean. Above, this would mean that about 1/3 of the time, the daily change in gas prices at Henry Hub has been more than \$1 to \$3, compared with more like \$.25 in the early 1990s (when the gas “bubble” had not yet burst). In fact, gas prices are not normally distributed. The normal distribution is the familiar, symmetric bell-shaped curve, but gas prices do not fit this pattern. They are capped from below at zero, while they can become arbitrarily large, at least in principle, so their distribution is said to be skewed. This is typical of most commodities. This has implications for risk management, discussed later.

Much like spot prices have become more variable, forward prices for natural gas have also been quite lively in the past few years. Figure 3 shows a few recent examples of the monthly forward prices quoted at approximately 6-month intervals over the past two years. Consistent with spot prices, forward prices have fallen recently by more than half from their peak in the middle of 2008.

Figure 3

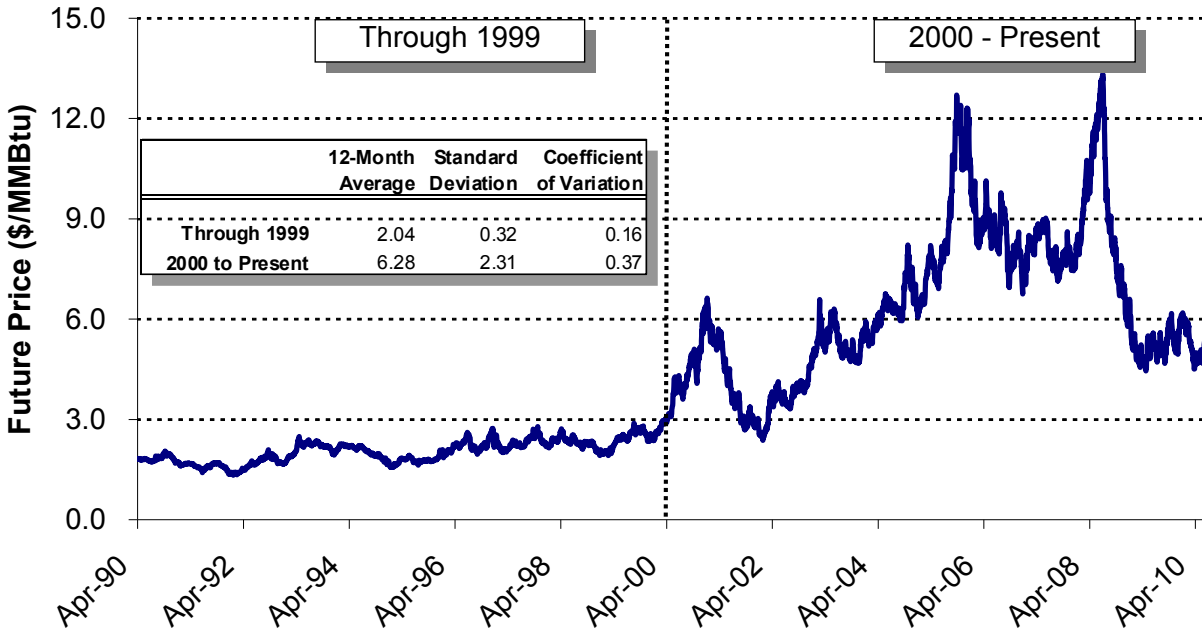


Source: Platts.

A longer term view of this change in forward prices, and their tendency to be more volatile in the past few years than in the prior decade, is seen in Figure 4 below. It presents the average price per MMBtu for the entire 12-month strip beginning in the first full month ahead of each trading day.

Figure 4

**NYMEX Natural Gas 12-Month Average Future Prices  
(April 1990 - June 2010)**



Note: Null prices are omitted to adjust for market inactivity.  
Source: NYMEX data obtained from Bridge & Bloomberg.

In this graph, the difference between the 1990s and the 2000s is even more dramatic than was the case for spot prices. As seen in the summary box on the left of this chart, average annual forward prices have been about three times higher in the past ten years, and the standard deviation of forwards has been about seven times higher. Even in percentage terms, this is much higher recent volatility; the coefficient of variation (standard deviation over mean) is more than twice as high for the 2000s as in the 1990s.

In this context, efforts to hedge natural gas price risk have become much more important for many but not all market participants. As we will discuss in this paper, there are many means of hedging, and the hedging needs of market participants varies depending on their specific circumstances. Those entities that face costs and revenues that are correlated (i.e., that tend to vary together) may not need to hedge. Entities that have costs and revenues that move independently (e.g., with costs driven by gas but revenues driven by an internationally traded product affected by many other factors) may need to hedge to protect margins and simplify operations. Correspondingly, there is no one standard extent or horizon for volatility reduction that will be useful for all market participants. Market participants should be hedging to mitigate exposure to specific problems that would emerge for their business if gas prices were to reach extreme levels (either high or low). Since these problems differ among gas market participants, the risk management programs they use will be specific to their situations. Hedging horizons may also vary. A gas producer may be concerned about prices in the coming few years in order

to cover well development costs, while an electric utility with a gas-fired peaking plant may only be concerned about the next few days or weeks.

The increase in gas price volatility during the 2000s was accompanied by a general shift in financial trading and management practices throughout the U.S. economy that resulted in a heightened level of commodity and financial risk management in the United States. On the demand side, following the first of the major gas price spikes in the winter of 2000-2001, several state regulatory commissions launched investigations into the risk management practices of the gas distribution or electric utilities they regulated, with an eye towards understanding the ability of utilities to mitigate customer exposure to natural gas price volatility. This was a particularly big issue given the tendency of gas utilities to procure gas at monthly index prices (rather than under fixed price contracts) and the predominance of purchased gas adjustment clause (PGA) mechanisms that allowed most U.S. gas utilities to pass through their gas costs to customers. Several utilities started or expanded their hedging programs, to the point where now the majority of gas distribution companies use some hedging.<sup>3</sup> Also contributing to a growing demand for hedging was the shift in the late 1990s towards vertical unbundling and retail access (supply competition) in the electric utility industry. This created a need for tools to mitigate the very high volatility of wholesale spot power markets. Gas hedging was particularly useful, because natural gas is often the marginal, price-setting fuel in power markets. On the supply side, many major financial institutions, often investment banks, became very active in supporting this need.

The price spikes over the past decade highlight an intriguing issue for the natural gas industry: Is the price volatility experienced over the past decade anomalous, or is that what we should consider normal? If it was an anomaly brought about by ill-conceived practices and misguided expectations in other sectors of the economy, then perhaps we can look forward to a period of future calm. On the other hand, that calm period from around 1985-2000 is considered by many economists to be a period of over-supply induced in large part by how we deregulated wellhead gas production—making the low volatility largely a result of these non-repeatable conditions, and making the most recent decade seem the more normal.<sup>4</sup>

Today we appear to be experiencing another period of at least temporary over-supply due to:

- 1) the shale gas boom that is now occurring as a result of technological breakthroughs in horizontal drilling and hydraulic fracturing,
- 2) excess LNG capacity caused by fears that U.S. gas supplies were becoming quite tight, and
- 3) the economic crisis and resulting reductions in gas demand.

---

<sup>3</sup> A 2006 AGA survey found that 87% of the responding companies used financial instruments to hedge at least a portion of their supply purchases (compared to 55% three years earlier). See “LDC Supply Portfolio Management During the 2005-2006 Winter Hearing Session”, American Gas Association, September 7, 2006.

<sup>4</sup> Another factor that many economists believe contributed to the calm period in the 1980s was the Powerplant and Industrial Fuel Use Act of 1978. The Fuel Use Act restricted the construction of natural gas-fired power plants and industrial use of natural gas, thereby limiting demand for natural gas in the United States. Portions of the Fuel Use Act were repealed in 1987, allowing new development of gas-fired power plants and increased industrial use of natural gas.



This shale boom may not have yet reached its own “typical” conditions, since there has been competition to claim and develop leasehold properties at a rate somewhat above what may have been otherwise economic. Nonetheless, there is considerable optimism that we may be going to enjoy decades or more of moderately priced gas from this non-conventional source. Onshore shale supply sources may also make us less dependent on Gulf Coast supplies that are particularly susceptible to hurricane damage, reducing future exposure to the types of hurricane-induced price spikes that were experienced in 2005. In addition, shale gas supplies could reduce basis values in some market areas, such as the U.S. northeast. Likewise, we are not yet able to say much with confidence about the rate and potential breadth of economic recovery. Several public policy initiatives will impact gas market prices and risk, including climate policy legislation, renewable electric generation, tightening air quality regulations that could cause coal plant shut-downs due to the high costs of compliance, demand conservation programs, and R&D support for technologies such as compressed natural gas vehicles, electric vehicles, fuel cells, and the like. Time will tell whether we are in a new norm of comfortable, deep supply and low risk comparable to the 1980s and 1990s or in a long period of technology and market adjustments that are likely to be reflected in volatile conditions such as were seen throughout the past few years. At the very least, it would be safer to be prepared for the latter and be happily surprised if the former occurs.

This paper reviews the tools and techniques for managing natural gas price volatility, and discusses how the use of these techniques tends to vary across different types of market participants in the natural gas industry. We begin by discussing the concept of volatility more formally and by describing some of the typical characteristics of gas price risk. We then describe the essential concepts behind risk management and discuss the limitations of risk management programs. We also provide case studies of hedging programs to highlight the differing objectives of these programs depending on their specific purpose.

## II. GAS MARKET RISK CHARACTERISTICS

### VARIABILITY VS. VOLATILITY

Formally, “volatility” as the term is used for risk management is not a measure of variability, but a measure of unexpected variation around a mean, a trend, or other known and foreseen patterns. If a contract has a price that varies from month to month according to some fixed and *a priori* known amounts, that variation is not volatility. It is simply riskless, known variability. For instance, the seasonality seen in monthly forward prices is a source of cost variation for a party holding either side of the contract, but it is not a source of risk or volatility. More generally, if a commodity has typical seasonality, the portion of that seasonality that is already reflected in forward prices is not volatility, but the deviations from those expectations that occur are volatility. Likewise, the changes in the level and shape of the forward strip from day to day are unexpected and are a source of volatility. The measure of volatility will depend on the time frame of interest (e.g., daily or monthly gas prices, or a longer period), the time period spanned by each observation, and how expected variation has been removed from the data.

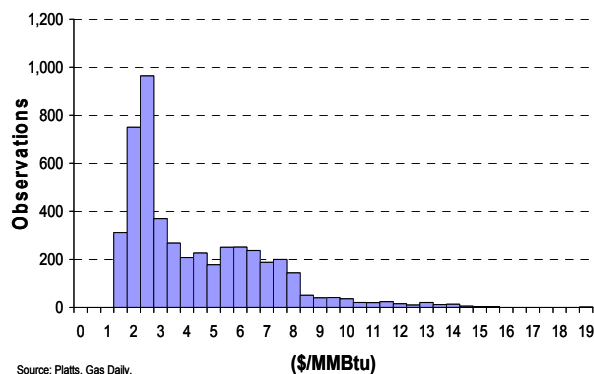
This distinction between variability and volatility may be irrelevant to some gas users. In particular, end-users of a gas distribution company will likely have little idea of what the forward-price expected seasonality is, and instead may regard the monthly increases in the winter as a source of risk, or at least a nuisance. So it may be useful to study both overall variability and volatility, depending on the purposes for gas price risk management. One way of thinking about the distinction is that nothing can be done with hedges or risk management strategies to eliminate the expected variability. A forward contract for next winter will inherently reflect a seasonal premium, albeit perhaps a different one depending on when the contract is struck. All that a hedge can do is limit the unexpected variation around that expected seasonal price. On the other hand, much can be done with financing strategies to redistribute expected seasonal variations over time. For instance, it is possible to find a financial market participant in gas trading who will levelize the annual strip of monthly forwards for a premium that reflects the interest carrying costs of selling at one price while buying at another. Technically, this is not risk management, just financial contracting. We will not discuss this aspect of variability smoothing further, instead just focusing on what can be done about the unexpected price movement ranges.

### Price volatility vs. Returns volatility

It is also important to distinguish absolute price volatility from percentage volatility. As was shown in Figure 4, both the levels and standard deviations of prices have increased in the past few years. If both had increased proportionately, there would be no increase in the amount of risk per dollar of forward obligation. This distinction is captured by measuring volatility in terms of “returns” rather than absolute price movements, where returns are the percentage change from day to day in the given contract. Mathematically, they are calculated as the natural logarithm of the ratio of today’s price over yesterday’s price. These return distributions take out the effects of the price levels changing in proportion with the variability. They also tend to

eliminate the skewness of price distributions. Figures 5 and 6 below demonstrate this. Figure 5 is a histogram of how frequently various daily price levels have occurred in the Henry Hub daily spot price over the last 20 years. It is skewed to the left, in part because prices cannot fall below zero, so there is a lower bound. However, this distribution has a long “tail” to the right, indicating that high price levels can occasionally occur, infrequently, but unlimited in principle.

**Figure 5**  
Histogram for Henry Hub Spot Price Data  
(1991 through 2010)



**Figure 6**  
Histogram for % Daily Henry Hub Price Changes  
(Returns)

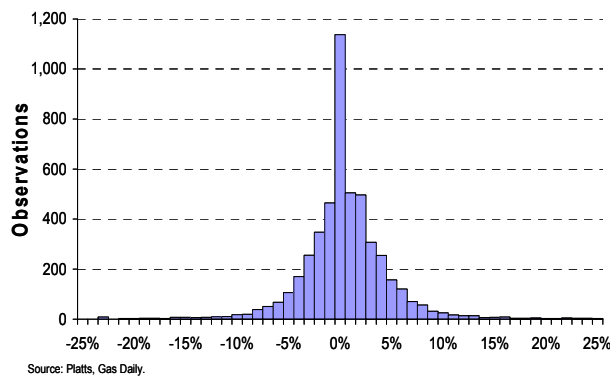


Figure 6 takes the exact same data and expresses it in terms of % daily changes, i.e., returns, and the result is a very symmetric distribution that has the familiar bell shape.

The distributions of returns for many commodities is in fact normally distributed, which means the corresponding price distributions are “lognormally” distributed – i.e., their logarithms are normally distributed. Lognormality means that a 10% price change for a given time interval is equally likely regardless of whether the prevailing price is low or high. As a result, a trader can use the same strategy to hedge a \$100 worth of exposure to forward gas positions regardless of whether the forward price is high or low. Most risk management techniques utilize tools focusing on returns rather than price levels. This is because the analytics are cleaner and because energy traders are usually interested in the risk per dollar invested or per exposed dollar, rather than the absolute variability they may face. Their counterparties who will sell them hedges are similarly inclined. It is also easier analytically to deal with normal distributions, which returns have. For instance, it allows the standard deviation (of returns) to characterize the shape of the whole distribution, while other terms (such as measures of skewness) are needed for price distributions. To manage total financial exposure, return risk can be translated back into dollar terms.

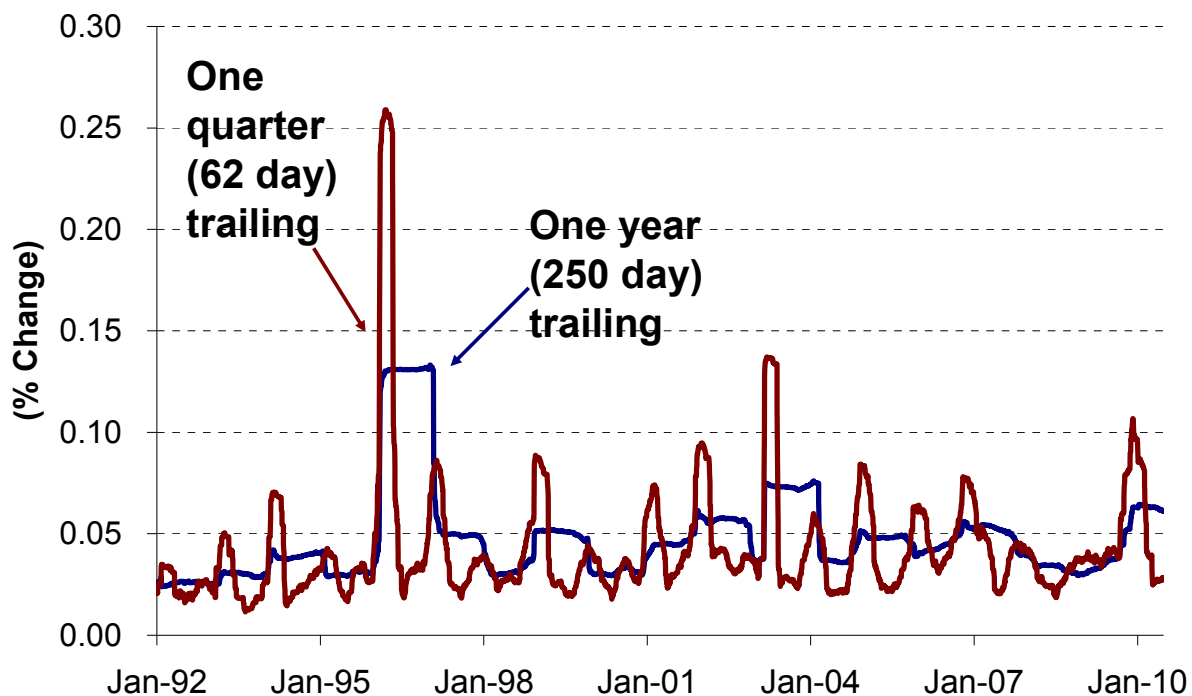
On the other hand, the absolute, price-based measure of risk (as shown in the standard deviation of prices) is likely to be what matters most to end-use customers who pay for each MMBtu that they purchase. This may also be the most relevant metric for long-term investment planners. End-use customers, including those who are making investments in gas-using equipment, are concerned about the absolute risk surrounding potential dollar outlays (e.g., is there a chance a customer will pay \$8.50/MMBtu versus an expected payment of \$6.25/MMBtu). Likewise, an end-user who burns gas as an input or feedstock and cannot pass through increases in the price of

gas in the sale of their final product (e.g., due to competition, as in the fertilizer industry) will also probably be interested in absolute price volatility. Such an end-user will likely have a sense that a \$1/MMBtu increase in the price of gas will adversely affect profits by some amount.

When one reviews the history of returns and their volatility for gas securities, a somewhat different interpretation of gas risk emerges. Figure 7 shows the rolling average of historical standard deviations in daily gas price returns at Henry Hub, comparable to Figure 2 above that was based on actual price movements. In Figure 2, the standard deviations had clearly increased markedly in the past few years, while that is less so for returns.

**Figure 7**

### **Yearly and Quarterly Rolling Volatility of Returns**



Source: Platts, Gas Daily.

While there is still a clear increase in return volatility over the past two decades, it is more like a doubling of risk than an increase of four to ten times, such as was seen in the raw prices.

### **GAS MARKETS AND AVAILABLE HEDGING CONTRACTS**

In U.S. gas markets, physical gas is typically traded on a monthly or daily basis at roughly 70 locations throughout the country. Even longer-term contracts are for fixed or specified volumes but with pricing provisions that usually index the unit cost of gas under the contracts to one of the monthly price indices that are published by leading gas trade publications (e.g., Gas Daily or Inside FERC). The index publishers will survey market participants that trade fixed price gas on

either a monthly (bidweek) or daily basis and publish an index that reflects the average gas price among the fixed price deals that were transacted and reported to the trade publication in its monthly or daily survey.

The benchmark price location in U.S. gas markets is the Henry Hub in Louisiana. Henry Hub is a location where there is physical gas trading (for buyers that want to take delivery of the physical product). It is also the location of the standard gas futures contract that is traded on the New York Mercantile Exchange (NYMEX), which is a financial product traded among buyers and sellers who do not usually make physical delivery of natural gas. All NYMEX natural gas contracts are for 10,000 MMBtu, for delivery to the Sabine Pipe Line Co. at Henry Hub in Louisiana. Natural gas futures contracts are tradable contracts that can be bought or sold today for delivery of gas sometime in the future. Specifically, gas futures contracts are traded for forward months, ranging from 1 month to 120 months forward (although there is often little trading of futures contracts past 36 months forward).

Gas trading at other U.S. locations (outside of Henry Hub) may trade either at prices that are higher or lower than Henry Hub, depending on regional market conditions and available transmission capacity between locations. These positive or negative differentials to Henry Hub are known as “basis differentials,” which tend to vary seasonally. Basis swap contracts are traded for many locations that allow market participants to lock in a transportation cost from Henry Hub to the receipt location.

Basis risk is an important consideration in U.S. gas markets since the price differentials between different locations can vary significantly over time, sometimes (albeit rarely) as much or more than the volatility in prices at Henry Hub. This is especially likely if there are constraints on pipelines at periods of high demand, such as during the winter or after a major weather disruption such as a hurricane, that can cause price spikes in destination markets. Some market participants are able to avoid the risk of these types of constraints by purchasing storage in market areas, where it is available. Basis differentials can also vary over time as a result of new pipeline construction and new sources of supplies entering new markets. A recent example is the decline in the west to east differentials in the U.S. that have occurred as a result of the construction of the Rockies Express and other pipelines.

An example of changing basis differentials is seen in Figure 8 below showing the basis between New York (Transco Zone 6) and Henry Hub.

Figure 8

<b>Transco Zone 6, N.Y. - Henry Hub Basis Differential (\$/MMBtu)</b>				
[1]		<b>April 2009 - October 2009</b>	<b>November 2009 - March 2010</b>	<b>April 2010 - June 2010</b>
		[2]	[3]	[4]
Transco Zone 6, N.Y. Average Price	[a]	3.86	6.18	4.62
Transco Zone 6, N.Y. Standard Deviation	[b]	0.62	2.35	0.42
Henry Hub Average Price	[c]	3.49	4.86	4.27
Henry Hub Standard Deviation	[d]	0.54	0.94	0.40
Zone 6 - Henry Hub Average Basis Differential	[e]	0.37	1.32	0.35
Zone 6 - Henry Hub Standard Deviation	[f]	0.16	1.67	0.06
Zone 6/Henry Hub Correlation	[g]	0.97	0.81	0.99

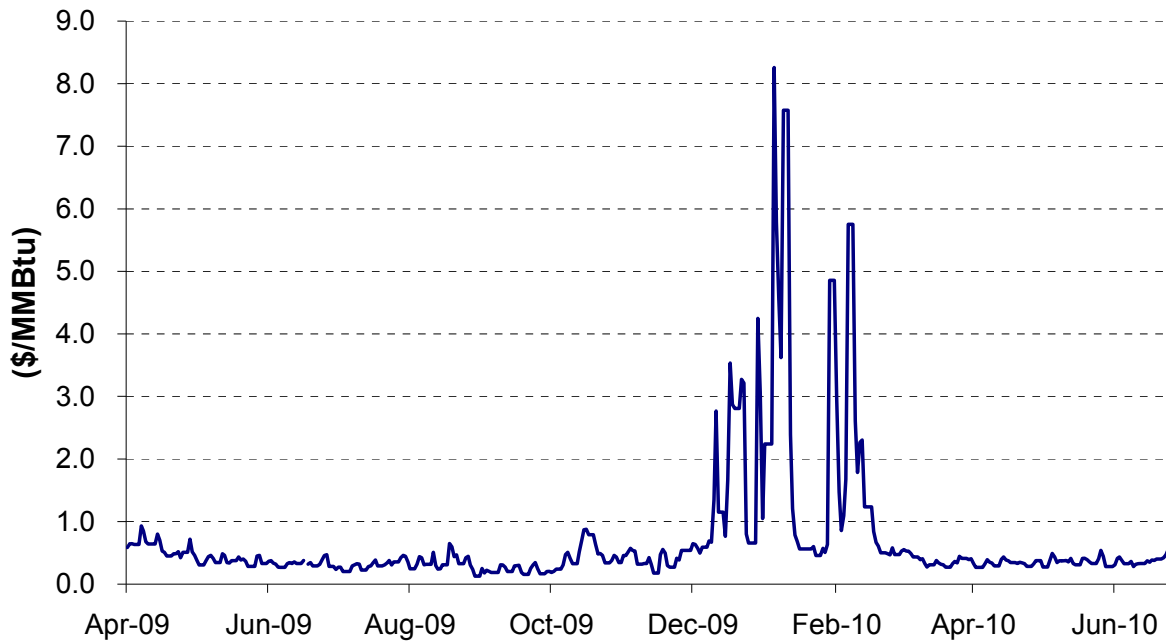
Sources:

[2], [4]: Platts, Gas Daily.

Figure 9 below presents this basis price behavior on a daily basis for every day over the past year.

Figure 9

**Transco Zone 6, N.Y. - Henry Hub Average Basis Differential (April 2009 - June 2010)**



Source: Platts, Gas Daily.

Noteworthy here from a risk perspective are the occasional extreme levels. Most of the time, the basis is pretty low and pretty stable, but it has skyrocketed to several dollars per MMBtu under conditions of tight supply.

### **FORWARD PRICE RISK PREMIUMS**

Standard gas futures contracts are traded for up to 120-months forward (although in practice most trading is for the coming 1-36 months). Continuously throughout each day, market participants can see the price for each forward month's contract. As previously demonstrated, forward prices move around considerably from day to day as expectations about the future change. Some traders believe this variability necessarily implies that there will be some kind of risk premium implicit in the price at which buyers and sellers will agree to trade forward, but this is not necessarily correct. There can be a premium, but it is not necessarily for risk and it is not always even positive. This view probably arises largely because it often is the case that forward prices turn out to be higher than spot prices. While this could be due to a limited supply of willing forward sellers, or buyers' desperation for hedges to offset problems they face if gas costs should exceed their budgets, it is more likely that this pattern is a result of skewness of spot prices. In equilibrium, forward prices have to be a good alternative to the full range of possible spot prices. As was shown in Figure 5, that distribution is skewed, with some small chances of very high prices. Most of the time, the high price outcomes do not occur -- but the forward price has to reflect that possibility. Thus, the expected future spot price is above the mode (most likely) price, so the realized spot price will usually be below the prior forward prices. This is not a premium for risk, just a forward reflection of the full range of potential spot prices.

Because this is not a true risk premium, it is not a cost of hedging that could be saved or avoided by not hedging. That will be true often, but not all of the time, with no net advantage over the long run. This is akin to the fact that you cannot expect to save money over the long haul by not insuring your house. It is true that you will have many years of not paying for the insurance, but they will be wiped out if/when your house burns down.

### **VOLATILITY TERM STRUCTURE**

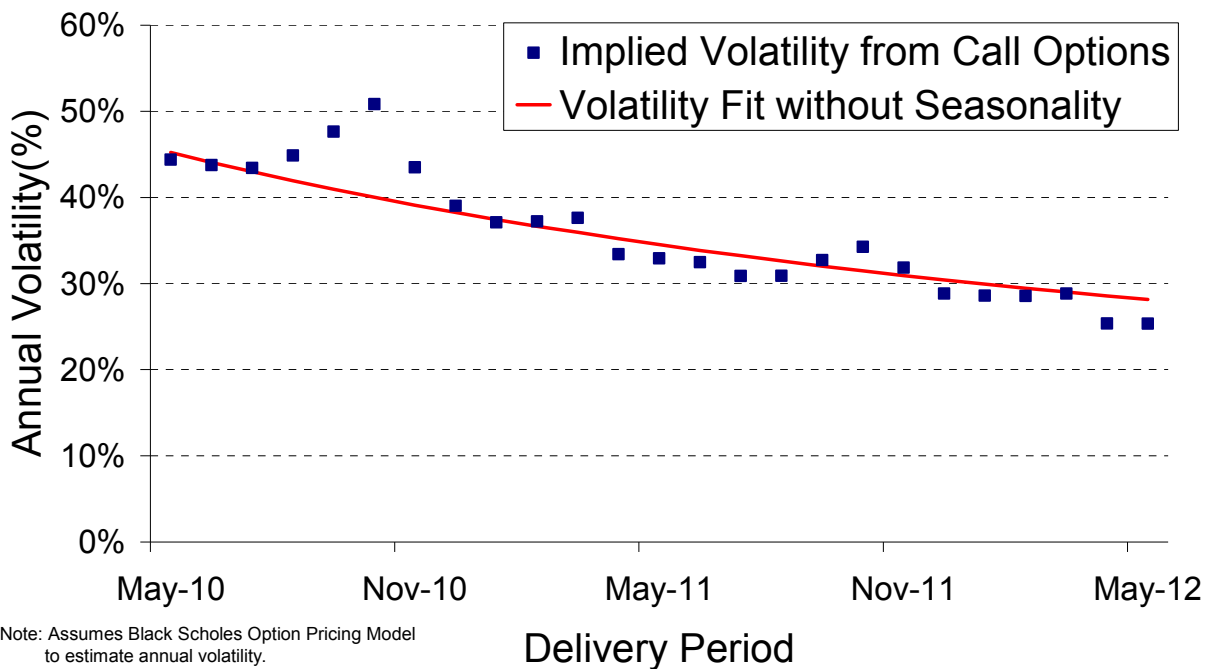
Much as forward prices can have a term structure, i.e., a slope that reflects whether future conditions are expected to be tighter or looser than current markets, volatility also has a shape over time, which is also called its term structure.

Volatility term structure refers to the relationship between price volatility and time to (and of) delivery. The relationship is generally a declining one, meaning that the volatility of near-term contracts tends to be higher than out-month contracts, which decay to a steady lower long-term level. The volatility of forward month contracts is a measure of the amount of uncertainty foreseen in the potential changes in prices for a future delivery month between now and the delivery time. Obviously these amounts could (and do) vary by delivery month. They also vary by time until delivery, as explained further below. They can be calculated using historical futures price data (by calculating the standard deviation of daily settlement prices for contracts that are one month out, two-months out, etc.), on the assumption that historical patterns are

recurring. Or they can be inferred from forward option prices (that is, using option pricing models, from which implied volatilities for forward month contracts can be calculated).

An example of this volatility term structure relationship for gas is shown below in Figure 10, which plots the annualized broker-quoted volatilities as of April 2010 for the 24 month forward period. The seasonality of volatility generally corresponds to the price term structure (i.e., with forward winter prices displaying higher volatility). This figure also shows that the prompt month contracts tend to have the higher volatility than the more distant delivery dates. This is a result of “mean reversion”, a property found in many commodities.

**Figure 10**  
**Implied Volatility as of April 2010**  
**Using Henry Hub Nymex Futures & Options**



**Mean reversion**

Mean reversion refers to the tendency of gas prices to move back to a mean or typical level following price shocks (either upward or downward) arising from relatively short-term, non-persistent conditions. In the long-term, these shocks are dampened because both supply and demand are more elastic over longer horizons. For example, a period of tight supplies and high demand after a hurricane might lead to a price spike. But eventually, this price spike itself will encourage repairs and possibly new production being brought on-line, and it may also induce some demand destruction, such that prices eventually decline to a more normal level. Conversely, a current fall in prices will tend to cause reduced production and/or heightened demand, causing prices to climb back up. In general, there are many possible short term



influences on market conditions that will affect prices for a while but are mostly inconsequential over the long run. The long run price tends to reflect beliefs about long run marginal costs, which is more sensitive to shifts in beliefs about systemic, large influences, such as changes in technology or regulation. These beliefs generally change more slowly, so distant prices tend to be less volatile. It is not unusual for the near term volatility to be several times higher than the long run volatility.

This declining sensitivity with longer horizon is shown by the red, smoothly declining line fitted to the monthly volatility quotes in Figure 10 above. Lower distant-period volatility does not mean future obligations actually involve less total risk between now and their delivery dates than near term obligations. Rather, it means that the variability over a given, short time frame (such as over the next day or week) is lower per dollar invested in a long term obligation than in a near term position. Cumulatively, over all the time remaining until the long term position is closed out, it will have more total risk.

For risk management, the implication of mean reversion is that one can only use the current term volatility structure to evaluate risks of portfolio positions that are unhedged or susceptible to future value changes at that time. For instance, if forward positions are going to be procured in periodic, regular installments over time, as many gas utilities do, then the risk associated with pending future purchases will depend on when they are going to be made, not just the month they will be covering. Fortunately, there are analytic solutions to how to make such adjustments.<sup>5</sup>

---

<sup>5</sup> See for instance “Modeling and Estimating the Forward Price Curve in the Energy Market” by Carl Chiarella, Les Clewlow, and Boda Kang, Quantitative Finance Research Centre, University of Technology, Sydney, <http://ideas.repec.org/s/uts/rpaper.html> Research Paper number 260.

### III. RISK MANAGEMENT PRINCIPLES

Risk management refers to practices for: (1) forecasting and measuring the foreseeable range of uncertainty in future costs and revenues, (2) simulating how alternative supply or sales portfolios and hedging, procurement or sales practices (type, timing, and relative size of different kinds of wholesale contracts and securities) could alter the range of future risks, (3) scheduling and controlling for how procurement or sales occur and how they are adjusted over time in order to keep the range of potential net costs or revenues within desired limits, and (4) monitoring and evaluating performance through reporting mechanisms.

While these practices are widespread throughout many industries, and most of the natural gas industry, there are some persistent misconceptions about risk management that are worth addressing. In the remainder of this section, we discuss five key principles of risk management:

- 1) Risk management cannot change expected costs; it can only protect against problems that arise at extremes, for a fair price
- 2) Risk management is not done for its own sake, but to protect against other indirect costs that would arise when gas prices reach extremes
- 3) Hedging cannot remove all risks; in fact, it can involve its own new risks, such as credit and liquidity difficulties
- 4) Ex-post comparisons of hedging results to alternative procurements or hedges are likely to be poor indicators of performance

*Principle #1: Risk management cannot change expected costs; it can only protect against problems that arise at extremes for a fair price.*

A common misunderstanding, sometimes aggravated by risk managers themselves, is that risk management is undertaken as a way to reduce costs of the hedged items themselves. This is incorrect. Hedging may help a company reduce other costs (see Principle #2), but the expected cost of the hedged commodity itself will not be affected by risk management. Of course, after the fact it will often be the case that hedged positions are cheaper than unhedged ones would have been, but on average and in expectation that cannot be the case for fairly priced hedges. Risk does not simply disappear under hedging. Rather, it is transferred to some third party, or financed to smooth out cost or revenue variations over time. The proverbial saying is correct that “there is no free lunch.” In order for a risk transfer to reduce or avoid costs for the hedge buyer, then the hedge seller would have to be incurring the corresponding increase in its costs, and this will not occur absent fair compensation – hence no net reduction in overall expected costs.

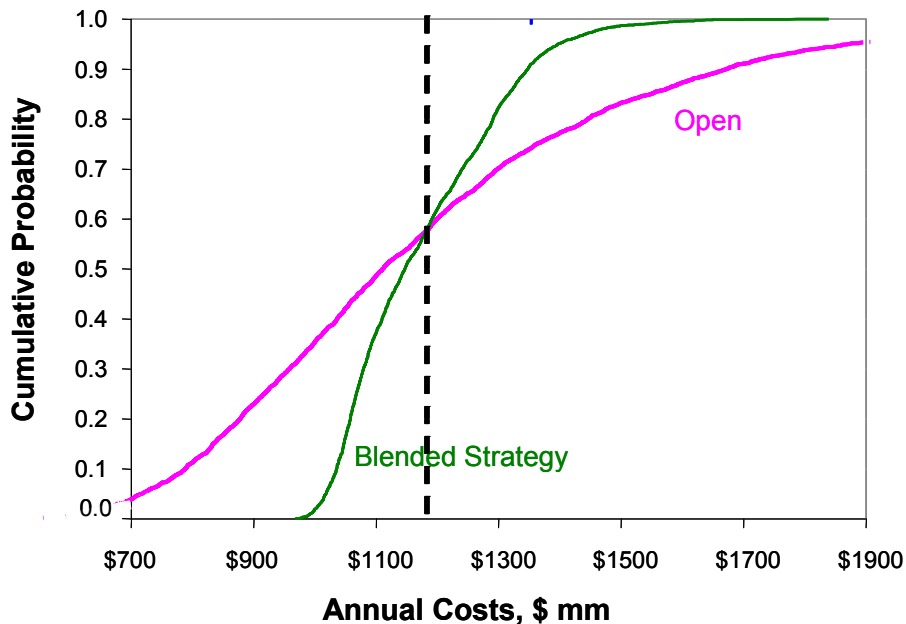
In a competitive and active, liquid market, all the available hedging instruments and contracts have (on any given day, for a given delivery period) the same expected cost and the same net present value. If not, the speculators will move in and out of the mispriced alternatives until their relative prices adjust to eliminate arbitrage opportunities. This parity is explicitly the case for a forward contract for natural gas, which is a commitment to transact a fixed quantity of gas at some date in the future at a stated price. That stated price has to cover, on a risk-adjusted

basis, what the seller thinks the gas will be worth in the spot market at the delivery time, and this is also the buyer's alternative of going unhedged (i.e. buying in the spot market). So the contract trades at a fair price which gives neither of the parties an expected gain or loss compared to not hedging at all. For that reason, the contract has zero value on the day it is bought, and no money is exchanged between the parties. They have each made offsetting future promises to each other that are matched in value. Even if volatility is capped on just one side, as with option contracts, that truncation of possible prices is obtained for an up-front price that covers its expected value. Again, there can be no expected cost savings if the options are fairly priced.

So it is not reasonable to expect that hedging will lower one's costs over time. Instead, hedging is going to trim the extremes of potential outcomes without shifting the center. A graphical example is provided below in Figure 11. The pink line shows the annual cost uncertainty facing a buyer of natural gas who procures gas on a pure spot basis (i.e., under contracts that are indexed to monthly spot gas prices) to supply its LDC customers. Specifically it shows the probability of different levels of expenditures on yearly gas costs as foreseen 18 months in advance of the delivery year. That buyer expects to spend a little over \$1.1 billion on yearly natural gas purchases, as seen by the dashed vertical line. The rest of the S-shaped curve depicts the probability that the annual cost will be as low or lower than any given point on the x-axis. Since this buyer is intending to go unhedged, there is a chance that realized natural gas prices will be low and result in expenditures of \$700 million (which has less than a 5% probability). Or, they could be extremely high and cause expenditures of nearly \$1.9 billion (with a 95% chance that costs will not be this high, and a corresponding 5% chance they could be even higher).

**Figure 11**

**Annual Procurement Costs Under Hedged and Unhedged Strategies**



The green line shows how a hedging strategy changes these outcomes. This strategy involves a procurement schedule that fixes some prices in advance through the use of regular, staggered purchases of gas futures contracts over time in the months before delivery. This approach limits both the downside and upside that could be experienced—but *the expected cost is still the same*. However, while the expected costs are the same with or without the hedging strategy, the distribution of potential outcomes has been reduced under the hedging program relative to being unhedged. The probability of paying in excess of \$1.5 billion is virtually nil under the hedge program relative to the spot program. Likewise, the likelihood of spending less than \$1.0 billion under the hedged program is much less relative to the spot program.

An important caveat: this discussion of hedging instruments and their expected net present value of zero assumes the products are traded in competitive markets where neither side has an information advantage. Under some circumstances, this may not be the case. For instance, if a very complicated, non-standard hedge is needed, there may be so few sellers that it is only available at a premium to its intrinsic risk-shifting value. Likewise, it is possible that in such complex situations, one side of the transaction will have superior information about the true risk. If so, the hedges may have a non-zero expected value.

*Principle #2: Risk management is not done for its own sake, but to protect against other indirect costs that would arise if/when gas prices reach extreme levels.*

If hedging in competitive markets has a zero expected value, why do market participants choose to hedge at all? In fact, some gas industry participants with large exposures to gas prices have chosen not to hedge. However, many market participants find that hedging is useful to prevent some other problem or indirect cost (not embedded in the expected cost of gas itself) that arises at extremes. Generally these indirect costs fall under the label of "costs of financial distress," with such manifestations as impaired credit ratings, lack of funds to pursue other needs or opportunities, and administrative complexities of dealing with a highly unstable financial or operating environment. The potential losses or inconveniences in those areas should be the reason for the type and timing of gas hedging they pursue. Absent such indirect costs for a firm or its customers, there is no real reason to hedge.

Note that these potentially significant indirect costs are not usually within the province of the risk management group itself. The problems to be avoided must be identified by senior managers of other functions. For example, a small natural gas producer might want to avoid a cash flow shortfall that could arise if it did not hedge its future production and spot gas prices were to fall dramatically. Such a cash shortfall might force the producer to cut-back its drilling program or, in an extreme scenario, lead to financial distress in which the producer could not meet its debt obligations. The producer might therefore hedge to lock-in a revenue stream in order to manage its cash flow. On the other hand, a major integrated oil and gas company may choose not to hedge its gas production if it is financially so strong that it can simply absorb the variation in cash flow that comes from shifting spot gas prices.

Thus, hedging is typically undertaken to obtain the benefits of reducing gas price volatility and avoid some other problem that could arise from exposure to extreme gas price movements. This means the proper amount of hedging does not just, or even primarily, depend on the risk properties of the gas prices themselves. If that were the case, then all users of gas would hedge in more or less the same way and to the same extent, since they would all see the same data and the same opportunity.

This principle is very commonly misunderstood by public utility commissions, who often seem to expect utilities to hedge simply because of the variability of fuel prices. They sometimes regard hedging as a part of “least cost planning” -- the normal standard for utility regulatory approvals. But except in this limited sense (of avoiding exposure to indirect costs), hedging and risk management by regulated utilities are not related to least-cost planning. Least-cost planning by utilities involves choosing between alternative supply (or conservation) options that have equivalent benefits but different costs. Risk management involves choosing between different hedging alternatives that have identical expected costs (ignoring minor transactions cost differences) but different benefits, *i.e.* patterns of exposure to future risk. Utilities have always been authorized and expected to pursue least-cost alternatives. In contrast, they almost never have received guidance for how much to alter the benefit (risk management) attributes of their services, because this has not been a traditional regulatory objective. The utility should work with its regulators and major customer interest groups to decide how much risk management is needed to adequately protect customers against their indirect costs of gas price volatility.

*Principle #3: Hedging cannot remove all risks; in fact, it can involve its own new risks such as credit and liquidity difficulties.*

A risk management program provides some degree of protection from extreme price movements, but it should not be expected to remove all the risk to which a gas market participant is exposed.

First, hedging is easiest when there is a fixed future volume of sales or supply that will be needed. If the future needs are uncertain, it is almost impossible to hedge them precisely, except by luck or by waiting until close to the time of need, when volume uncertainty has shrunk. This means leaving the price risk open for quite a while. For a utility, this could happen in an extreme weather scenario (such as an unexpectedly cold winter for an LDC, or a hot summer for an electric utility) that requires the utility to purchase more spot supplies than expected. Conversely, milder than average weather may make previously hedged volumes unnecessary, such that they have to be dumped at spot prices for a loss.

A substantial hedging program will usually introduce some new risks even as it eliminates others. In particular, it can create liquidity risks and counterparty performance risks, because locking in very long-term purchases or sales creates credit and collateral risks surrounding whether both parties to the transaction can and will perform, especially if market conditions shift materially after the hedges were entered. Thus, a gas buyer entering into a long-term fixed price contract at prices that end up being much lower than realized market prices will be exposed to the risk that its counterparty will not perform under the contract. If the counterparty does not perform, then the buyer will likely have to replace its expected purchases either from the spot

market or with a new long-term contract at higher fixed prices. While the long-term fixed price contract serves as a hedge against spot prices, it may become so valuable to the buyer as prices rise (and become more and more in the money) that the seller may seek to repudiate the contract, especially if it did not have its own hedges in place that reduced its risks in supplying the contract. (Longer term hedges also involve more of the aforementioned volume forecasting risk.) Even without performance defaults, if a hedge moves way “out of the money”, it may be necessary to post a large amount of collateral to assure the counterparty that the transaction will be completed. This credit posting can involve much bigger burdens on cash and liquidity than would have prevailed by remaining unhedged, potentially even bankrupting the hedger.

Indeed, even if complete inoculation were possible, this should not be the objective of most companies. Considerable human and financial resources are needed to manage risk well, and at some point there are diminishing returns to doing more of it. For instance, the credit and collateral risks of very long term hedging can consume some of a firm’s borrowing capacity or restrict its use of slack cash, at the expense of other kinds of business growth that would have otherwise been possible. Perhaps more importantly, if a firm is better than average at bearing certain kinds of risks, it should not just tolerate those risks but actively seek them out to position the firm for a strategic, competitive advantage in those areas.

Hedging programs are usually designed to cover risks up to a certain size with a certain probability. If extreme events occur that are more dramatic than were anticipated or would have been normal based on past patterns, then there will be open exposure. (See the later discussion below about VaR and its detractors in Chapter V.) A hedge program is only as good as its numerical inputs, and it is not easy to judge whether the key parameters are stable or not. If risk conditions are shifting, a program designed for historical conditions may be inadequate.

Finally, hedges generally cannot eliminate ultimate exposure to long term, large, secular influences on the economy or the industry as a whole. For instance, if/when CO<sub>2</sub> pricing is introduced as part of a climate protection policy, the price of CO<sub>2</sub> will ultimately be reflected in the price of natural gas. Although market participants may in the near-term be able to protect themselves from short term changes in the value of gas due to CO<sub>2</sub> by hedging gas prices, over a period of years, the CO<sub>2</sub> price must be more or less embedded in gas prices to reflect the penalty that CO<sub>2</sub> prices impose on natural gas and its associated emissions.

The main point is not that a particular risk is or is not mostly hedgeable, but that risk managers must manage the understandings of their executives, investors, or regulators so that unrealistic expectations are not imposed.

*Principle #4: Ex-Post Comparisons of Hedging Results to Simple Alternatives Are Poor Indicators of Risk Performance*

Some companies assess the performance of their hedging programs by comparing the after-the-fact results to simple alternative procurement schemes, such as all-spot procurement. For instance, a company may look back at the prior year’s hedging activities and calculate its total annual gas procurement costs (including any hedging gains or losses) and compare them to a

program of indexed purchases (either at monthly or daily index prices, or a combination of the two). These types of comparisons over short-term periods (such as a year) are not likely to be very useful in two respects. First, they can create false impressions of the performance of the program. Consider a utility that hedges and fortuitously achieves costs that are much lower than a spot procurement program. The comparison may create two, damaging false impressions: 1) that risk management can be expected to lower costs or raise profits because of commodity savings, and 2) that the responsible risk managers are exceptionally talented and should be expected to repeat that kind of beneficial performance next year. Unless the organization was explicitly and intentionally speculating that it had found a mis-valuation among gas contracts of different types, it is much more likely that what really happened was lucky timing of hedging prior to an unexpected price spike.

There is nothing wrong with that happy outcome, but it is not the point of the hedging, nor the right way to evaluate the success of the risk management efforts. It is better to keep the focus on whether the program continually adhered to its ex ante risk objectives, targets, limits, reporting and controls rather than on how attractive its ex post results turned out to be. That is, the important question will not be whether the hedging program achieved gains or losses, but whether the program had the effect of keeping procurement within the intended risk boundaries that were established prior to the implementation of the hedging program. To the extent ex-post comparisons are used, they should be used over long time-periods that will reveal how the risk program succeeded in reducing gas price volatility across a wide range of market circumstances, not just the most recent annual outcome.

This discussion is not to suggest that historical reviews have no place in a risk management program. One key question to ask is whether the assumed (simulated) risk parameters describing the market have shifted over time. If risk limits were occasionally exceeded, does this call for a new risk strategy, or just updated forecasts of input parameters? One place where it is especially useful to consider historical information pertains to correlation assumptions. Often, gas users are concerned about the correlation of prices at different locations, or across certain types of energy conversions. In particular, power producers that hedge a spark spread (the electricity margin over fuel costs) may want to understand historical correlations between electricity and gas and consider whether these historical correlations will hold to the same degree going forward. Gas marketers selling at citygate locations and buying at Henry Hub may likewise want to consider correlations between Henry Hub and citygate prices in their consideration of hedging the basis or locational difference. Structural analyses of historical versus forecasted conditions, and statistical analyses of how those conditions have affected correlations, may inform when and how to revise parameters.

#### IV. TOOLS FOR MANAGING NATURAL GAS PRICE VOLATILITY

There are many tools available to market participants who want to manage gas price volatility. These can generally be categorized as either physical, financial, or non-standard. The various hedging tools have different time horizons typically associated with them, as summarized in Figure 12. The remainder of this section provides more information on their advantages and limitations.

**Figure 12**

**Time Horizon of Alternative Hedging Instruments**

	Physical	Financial	Non-Standard
Short-Term (< 1 year)	<ul style="list-style-type: none"> <li>• Storage</li> <li>• Fixed-price contracts</li> <li>• Changes in production</li> </ul>	<ul style="list-style-type: none"> <li>• Futures, swaps</li> <li>• Options, collars</li> <li>• Weather derivatives</li> </ul>	<ul style="list-style-type: none"> <li>• Swing, peaking, no-notice provisions in physical contracts</li> </ul>
Medium-Term (1-5 years)	<ul style="list-style-type: none"> <li>• Fixed-price contracts</li> </ul>	<ul style="list-style-type: none"> <li>• Futures, swaps</li> <li>• Options, collars</li> </ul>	<ul style="list-style-type: none"> <li>• Outsourcing of physical supply portfolio</li> <li>• Alternative price arrangements in physical contracts                             <ul style="list-style-type: none"> <li>– Caps/floors</li> <li>– Index Averaging, S-curves</li> <li>– Base prices indexed to other commodity prices</li> </ul> </li> </ul>
Long-Term (6+ years)	<ul style="list-style-type: none"> <li>• Fixed-price contracts</li> <li>• Reserves ownership</li> </ul>	<ul style="list-style-type: none"> <li>• Liquidity issues with available products</li> </ul>	<ul style="list-style-type: none"> <li>• Outsourcing of physical supply portfolio</li> <li>• Alternative price arrangements in physical contracts                             <ul style="list-style-type: none"> <li>– Caps/floors</li> <li>– Index Averaging, S-curves</li> <li>– Base prices indexed to other commodity prices</li> </ul> </li> </ul>

#### **Physical Tools**

##### *Storage*

There are two main physical hedging tools available to gas market participants. The first is the use of natural gas storage as a within-year hedge on seasonal or shorter term price movements. Utilities expecting winter prices to be higher than summer prices (given that winter is the peak demand period in U.S gas markets) will purchase natural gas in the summer, inject the gas into a



storage facility, and withdraw in the winter (to avoid having to buy those quantities in spot markets during the winter period). Utilities that do not have access to storage in their market areas also sometimes use LNG peak-shaving facilities to meet demand in super-peak periods (the coldest days of the winter). These facilities liquefy pipeline-sourced supplies in summer periods and store them for winter periods, re-gasifying the LNG on the coldest days of the winter. Storage is also used for much shorter-term purposes than meeting seasonal requirements. It is used daily as a means of balancing mismatches between deliveries and burn requirements. Thus, a power generator who delivers gas to a plant that operates less than expected (perhaps due to short term weather conditions) may inject gas into storage for balancing purposes, or may also withdraw from storage if daily burn needs are unexpectedly higher than daily deliveries. These short term injections and withdrawals can be used opportunistically instead of buying and selling at spot, or paying for “swing rights” on a pipeline, depending on what is cheapest on a given day. Storage may also be used for arbitrage purposes in which a participant takes advantage of favorable price or basis movements.

Other short term, swing-like products are also available in the market, such as parking and loaning (“hub”) services offered by interstate pipelines, or hourly firm transportation contracts that allow market participants to take gas on a non-uniform basis over specified hourly periods. In addition, some marketers will provide swing supply services through gas supply agreements that charge a premium over the specified bidweek index price.

In terms of risk reduction, all of these physical strategies work by allowing the buyer to have a fixed payment for capacity (often cost-based) plus the flexibility gained from that capacity in lieu of more volatile and possibly unreliable access to spot supplies at the time delivery is needed. Storage also helps utilities avoid the need to contract for firm pipeline capacity all the way back to the production fields, and it improves their reliability of winter deliveries. Thus, it is not all about commodity price risk, though that is an important benefit.

### *Fixed Price Physical Delivery Contracts*

Another physical tool for managing natural gas price volatility is the use of fixed price natural gas contracts in which the buyer agrees to pay the seller a fixed price for a specified quantity of natural gas the seller agrees to deliver to the buyer. The alternative to a fixed price contract – and the type of contracting most-often used in U.S. gas markets – is an indexed contract in which the price is tied to a monthly spot price index that is reported and published by one of the gas trade publications. Fixed price contracts act a hedge for both the buyer and the seller since both achieve price-fixity for a portion of their portfolio and both remove the uncertainty associated with spot market prices. Although theoretically available for short-term, medium-term and long-term periods, fixed price contracting is not widely used in U.S. gas markets, especially for long contract durations. Utilities generally will not enter into such long-term contracts given concerns they have about regulatory review of such contracts (this issue is discussed in more detail below).

### *Changes in Production*

Many gas market participants have flexibility in their operations to alter production somewhat if gas prices become adverse, or more favorable. For instance, producers may be able to shut in (or open) wells as gas prices fall (rise), as well as alter their pace of development of new fields. Feedstock users may even have some opportunity to shift to another hydrocarbon, if relative prices move far enough. Power plant owners can change their dispatch between gas and other fuels, or between gas units and purchasing spot power. In most regional power markets around the country, natural gas is the marginal (last dispatched) fuel that often sets the wholesale price, but sometimes coal is on the margin and cheaper per MWh. In those situations, it may be better to buy power than to produce it, or better to produce more power than you need for your own customers and sell the excess at spot wholesale prices to other utilities making the reverse decision. These kinds of ability to adjust operations partly inoculate the gas user from full exposure to gas price volatility.

### *Gas Reserves*

Perhaps the longest-term hedge available to gas market participants is the acquisition of physical gas reserves. From a buyer's perspective, the purchase of production-area reserves is the ultimate lock-in of a fixed gas cost. But since the unbundling and deregulation of gas production in the 1970s and 80s, few companies have used upstream integration as a corporate strategy or risk management technique. A few instances where such a reserves purchase strategy has been used include Calpine, the independent power producer, which purchased gas reserves near some of its gas power plants (which it ultimately sold off). Similarly, Wexpro is a gas production company that sells natural gas to its affiliate Questar Gas (the natural gas utility serving Utah) at cost-of-service prices.

## **Financial Tools**

The financial tools for managing gas price volatility are traded financial products that do not require the actual exchange of natural gas. Among these traded products are futures, swaps, options, and weather derivatives.

### *Futures and Swaps*

Natural gas futures contracts are standardized, exchange-traded contracts that can be bought or sold today for delivery of gas in the future. The standard traded futures product is the gas contract available on the New York Mercantile Exchange (NYMEX). All NYMEX natural gas contracts are for 10,000 MMBtu, priced as if it was to be delivered to the Sabine Pipe Line Co. at Henry Hub in Louisiana. Contracts are traded from 9:00 AM to 2:30 PM each business day and can be purchased for delivery in any month from the coming "prompt" month up through about five years into the future. As shown previously in Figures 3 and 4, the prices fluctuate significantly and rapidly with changes in expectations about future spot (physical) supply and demand, and changes in the appetite for hedging. NYMEX posts daily and monthly settlement prices. The daily settlement price is the weighted average price of contracts traded in the last two minutes of trading. The final settlement price (at expiration) is the weighted average price

of contracts traded in the last half-hour of trading on the date that is three business days prior to the first calendar day of the delivery month. This date is referred to as the NYMEX settlement date.

Futures contracts allow buyers and sellers to achieve price certainty. For example, a buyer of a futures contract might purchase a January 2012 NYMEX futures contract today for \$6.00/MMBtu. If Henry Hub spot prices in January 2012 turn out to be \$8.00/MMBtu, the buyer will experience a \$2.00/MMBtu gain on the futures contract, thereby achieving an effective gas price in January 2012 of \$6.00/MMBtu (assuming the buyer purchases spot gas for \$8.00/MMBtu at that time). Likewise, if Henry Hub prices are \$4.00/MMBtu in January 2012, the buyer will experience a \$2.00/MMBtu loss on the futures contract, again achieving an effective gas price of \$6.00/MMBtu. The seller sees the same result, but due to opposite patterns of gains or losses.

Gas futures contracts are exchange traded products. There is no specific counterparty, just the exchange itself, which avoids financial performance risk from both sides, and increases the liquidity of its contracts, by “marking them to market” every day<sup>6</sup>. Basically, the difference between the original and most recent forward price is posted as cash by buyers or sellers, such that their positions are always in accord with the latest spot price for similarly dated transactions. When contracts for future delivery or settlement are traded bilaterally with a specific counterparty and without being marked to market every day, they are called forwards. These are commonly traded over the counter.

Swaps are similar traded products that trade on over-the-counter basis. A fixed for floating swap is an agreement between two parties in which the first party agrees to pay a fixed price to the second party for gas delivered at future dates in exchange for the bidweek price index at a specific location on those dates. Thus, for example, the purchaser of a swap might agree to pay a fixed price of \$6.00/MMBtu in exchange for the Houston Ship Channel (HSC) bidweek price index for all of the months in 2011. If the HSC bidweek index in March settles at \$4.00, then the buyer of the swap will pay \$2.00/MMBtu to the counterparty in that month. Swap instruments, like gas futures contracts, allow buyers and sellers to achieve price certainty.

No money is exchanged initially between buyers and sellers for forwards or swaps. They are set at future prices which both sides regard as a fair bet. Money is exchanged only over time, if/when those contracts move far out of market relative to then-prevailing views about gas prices at the same contract delivery dates. If the market price is well above the forward fixed price, the seller may have to post collateral to prove it will have the financial wherewithal to complete the

---

<sup>6</sup> For example, the basic idea of marking the market can be demonstrated by a simple example. If the futures price for January 2011 gas was \$7.50 today but moved to \$7.25 tomorrow, the buyer would have to post \$0.25 per MMBtu per contract it held to the exchange. This effectively replaces the old \$7.50 contract with the current \$7.25 one, with the paid \$0.25 covering the difference. This is done again the next day, and every day until delivery for both buyers and sellers. That way, the final, cumulative amounts paid are equal to the original price commitments, but you can liquidate your position any time at the current market price. In practice, these cash adjustments are taken out of margin requirements that are posted when the contract is initiated. Over time the adjustments are netted against the posted margin that may be increased from time to time if price movements have been large.

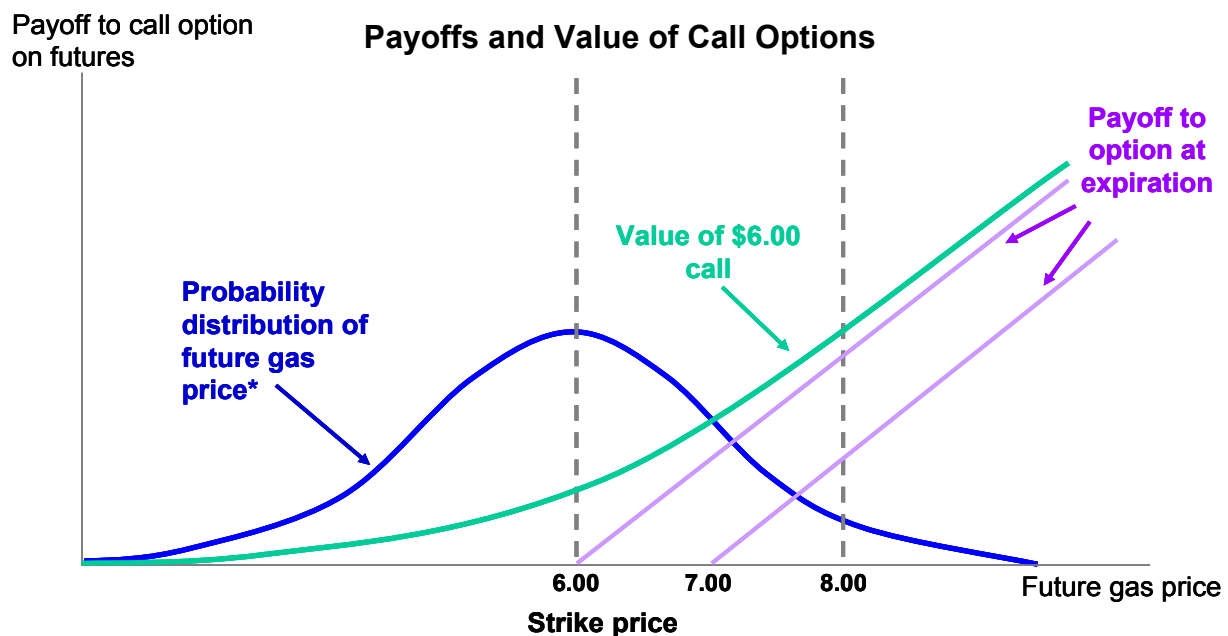
deal. Conversely, if prices drop a lot, the seller may insist that the buyer post collateral to cover the change in value.

### Options and Collars

A purchaser of a natural gas call option has the right but not the obligation to purchase a futures contract for a specified future month at a predetermined strike price. For example, a purchaser could buy a call option today for gas to be delivered in January 2012 at “strike” prices that vary by month. Only if bidweek prices are higher will the buyer of the option exercise his or her option rights. Most gas options are “European” options that can only be exercised on a specific day, the so-called maturity date of the option. “American” options can be exercised any time up to the maturity date, but it is generally not optimal to exercise before the maturity date, because there is still value in them from the possibility of moving more “in the money” (attractive to exercise) over the remaining time to maturity. Both can be sold before maturity for a premium that reflects their “intrinsic” value from immediate exercise (current market price less strike price) plus the value they have from uncertain, potential future growth in their value before maturity.

The purple lines in Figure 13 below show the payoffs to a purchaser of call options on the January 2012 futures contract at strike prices of \$6.00 and \$7.00. Thus, if the January 2012 futures price settles at \$8.00, the \$6.00 strike price call will have a payoff of \$2.00. The buyer in this instance will exercise the option, and purchase the futures contract for \$6.00 and sell it for \$8.00, thus realizing the \$2.00 gain. The buyer of the call option will thereby achieve an effective gas price of \$6.00 in January 2012. Likewise the \$7.00 strike price call will have a gain of \$1.00. Note if the January 2012 contract were to settle at \$3.00/MMBtu, the buyer will not strike the option and instead will let it expire worthless.

Figure 13



\*Illustrative distribution consistent with an assumed market price of \$/MMBtu; not meant to represent an estimate of current market conditions.

The buyer of the options shown in Figure 13 will have to pay an initial price for the option (known as the option premium) because it is like price insurance for a given volume of gas. Consider an eighteen month option with a \$6.00 strike price. Even if the current futures contract is also trading for \$6.00, the call option will have a value today greater than zero (zero is the intrinsic value that would be realized if the option were exercised immediately). This is because there is a year and a half until expiration and there is uncertainty in the futures price, which is shown by the probability distribution (in blue).<sup>7</sup> Since there is a positive probability of a positive payoff (and the worst payoff is zero), the option must have a value greater than zero. This is one of the features of options—they will have value above the lower bound payoff value as long as there is time left to expiration. The green line shown in Figure 13 shows the value of the call option relative to its lower bound payoff price (in purple). Even options with strike prices below current futures prices (which would have zero value if exercised immediately) will have values that are positive if there is time left until expiration given the uncertainty in futures prices (and the larger the uncertainty the higher the value of the call today). Thus an option requires upfront payment while a futures contract does not.

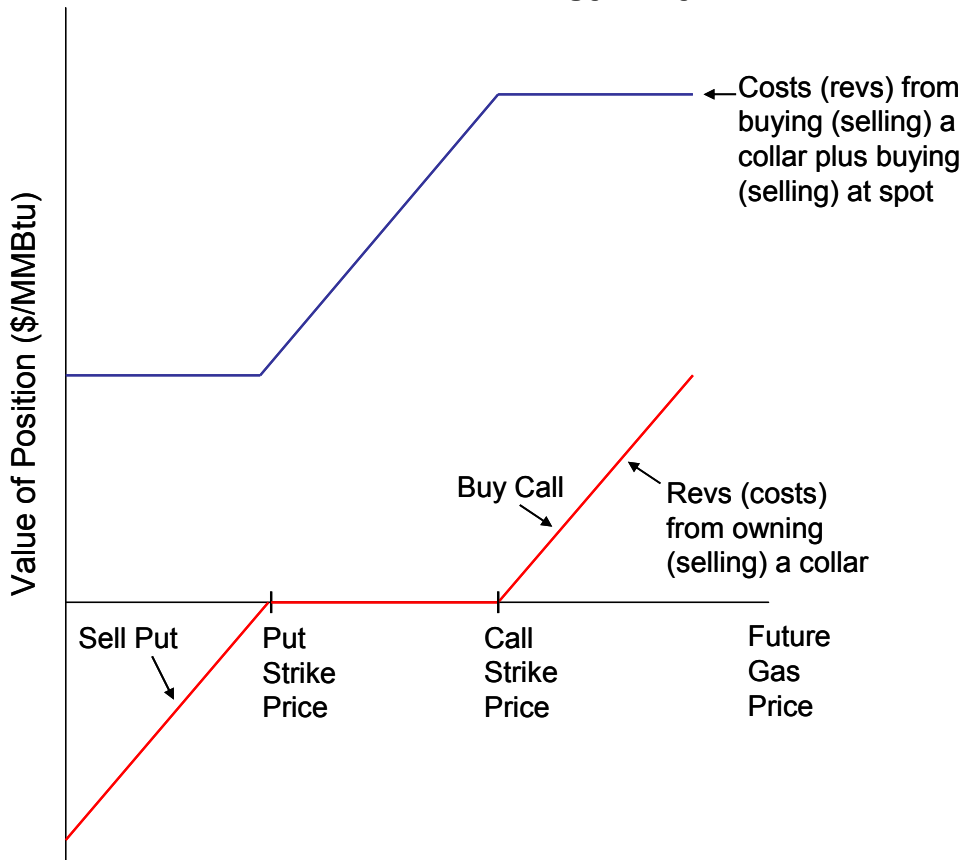
In practice, many market participants will use call option contracts as part of a larger “collar” strategy in which the buyer of call options offsets the expenditures it must make on call option premiums by simultaneously selling put options (and receiving premium revenues). By choosing the strike prices appropriately, the net cost may be zero (often referred to as a “costless collar”).<sup>8</sup> Doing so prevents the holder of the collar from fully participating in price declines (since the collar holder loses money on the puts it has sold, if prices fall below the put strike price). The payoff diagrams for owning a collar by itself, and owning it in conjunction with also buying spot gas to cover a fixed need of the same size as the option quantity, are shown in Figure 14 below (note that the buyers’ cost position from owning a collar and buying at spot is the same exposure as the sellers’ position from selling the collar and selling at spot). The collar strategy serves to cap prices if prices rise above the call strike price (since the collar holder receives a payoff in this instance), but also establishes a floor if prices fall below the put strike price (since the collar holder takes a loss for price reductions below this point). In between the two collar points, the holder of the collar faces the normal market risk.

---

<sup>7</sup> This is a stylistic representation of the price distribution and the associated option value, simply intended to show that there is some material chance the option could move to a higher value, because the right-side tail of the distribution of possible prices lies partly above the strike price. Recall that the actual distributions for gas prices tend to be skewed.

<sup>8</sup> A put option is price insurance for its owner against price declines; it gives the right, but not the obligation, to sell an asset at a future date at a fixed price. If you sell a put, you are acting as the insurance agent, taking the downside risk in exchange for a premium.

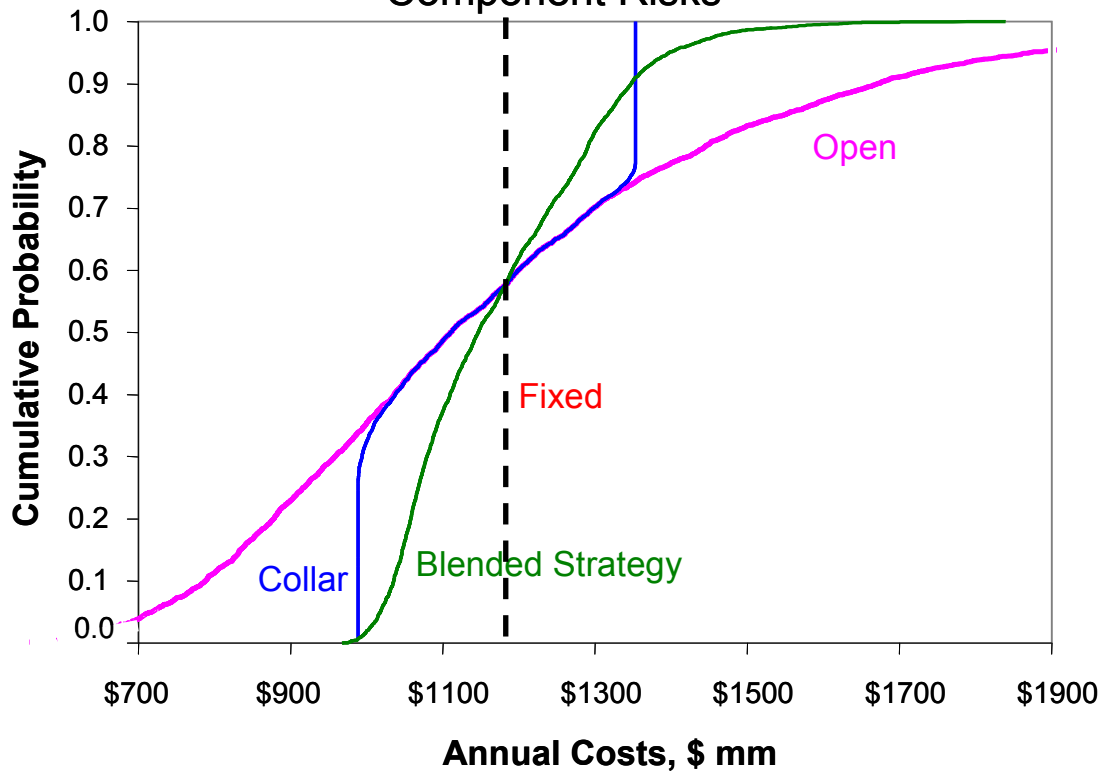
**Figure 14**  
**Collar Strategy Payoffs**



It is quite common in the gas industry to use a somewhat more elaborate collar, in which an additional put option at a lower strike price is bought by the gas buyer (or sold by the gas seller), all with the same counterparty. This makes the downside a bit less onerous for the buyer, because he or she no longer faces unlimited downside if the price falls below the sold put.

Figure 15 below is an elaboration of Figure 11. It summarizes the annual risk exposure for different procurement strategies, this time including a case with a collar strategy. As shown, an open or unhedged strategy (procuring at floating index prices) has the widest probability distribution. A strategy of just buying futures contracts for all volumes serves to fix prices, thereby allowing certainty in the cost of the portfolio (assuming that there is no volume uncertainty). Using a blended strategy (e.g. using futures for 50% of the portfolio and leaving 50% open) reduces the range of outcomes relative to the unhedged strategy. Finally, a collar strategy sets caps and floors on gas prices and establishes a more narrow range over which gas prices and costs can vary (relative to a purely open position).

**Figure 15  
Component Risks**

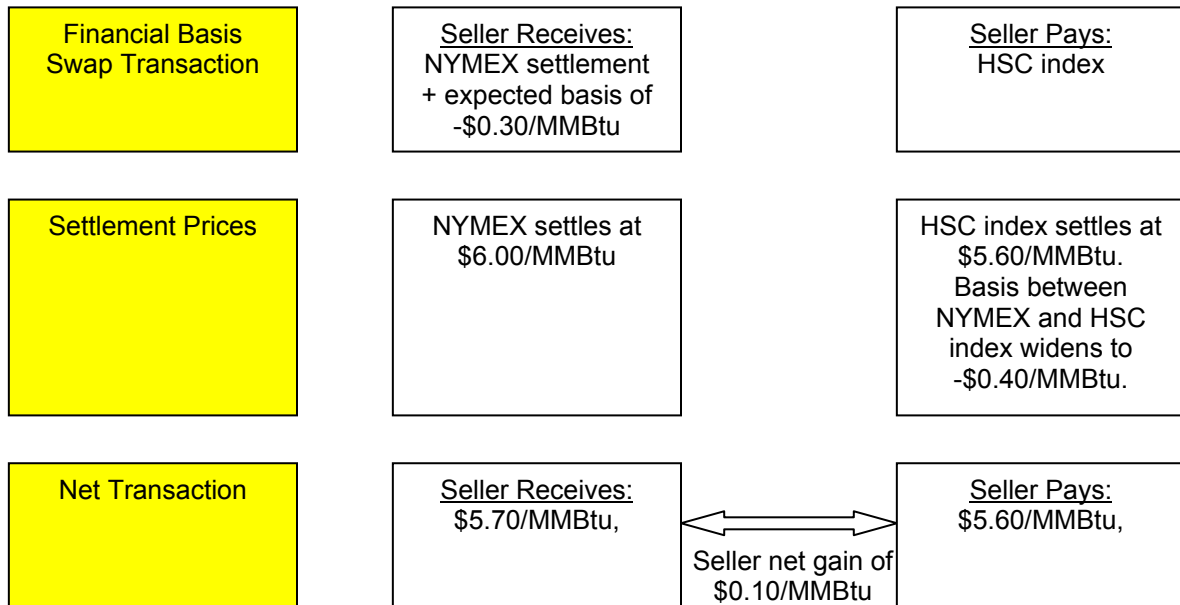


*Basis swaps*

A basis swap is an agreement where the seller agrees to pay a particular index price in exchange for the NYMEX settlement price plus or minus a stated fixed amount (e.g., minus \$0.30/MMBtu). The fixed amount is paid in lieu of the spot price for transportation to the delivery locations. In the example below in Figure 16, the seller receives NYMEX-\$0.30 and pays the Houston Ship Channel (HSC) index. Assuming NYMEX settles at \$6.00/MMBtu and the HSC index settles at \$5.60 (meaning a -\$0.40 basis), the seller will have a \$0.10/MMBtu gain. Thus, basis swaps can be used to hedge locational prices differences. A holder of pipeline capacity from the Permian Basin to HSC could lock in a margin on that pipeline capacity by selling HSC basis swaps and buying Permian basis swaps. As previously shown in Figure 9, basis risk can sometimes spike to quite high levels.

**Figure 16**

**Profits from Selling a Financial Basis Swap when the Basis Widens**



*Weather Derivatives*

A weather derivative is a contract that settles based on the value of a temperature index (typically expressed in “degree days”, the sum of deviations of daily average temperatures from 65 degrees over the course of a month). These contracts have been used by gas utilities to protect earnings from winters in which there is unusually warm weather. Like call options, weather derivatives can be structured to pay off fixed amounts if the weather is warmer than a specified number of degree days. Utilities tend to collect an appreciable portion of their revenues on a per therm (volumetric) basis, making their fixed cost recovery and resulting profits somewhat sensitive to sales volume. Weather derivatives can help mitigate this risk.

**Non-standard Contracts**

In theory, there are an infinite number of other types of contractual arrangements that could be used to limit gas price volatility. Practically speaking, the feasibility of a customized arrangement will depend on how readily its risks can be understood, how much the buyer is willing to pay for something that only a few sellers may be willing to offer, and how much confidence both parties can have in the other side’s long run willingness and ability to honor the contract over time, especially under adverse circumstances. Natural gas contracting in regions where there are not developed spot markets provides some useful examples. In Australia, long-term contracts (up to 15 years in duration) have been signed between producers and end-users



with a fixed base price that is subject to annual adjustments based on inflation indexes (which exhibit much less volatility than commodity prices). These contracts typically have price-reopener clauses that allow for a renegotiation of the contract to account for market shifts and contain arbitration provisions in the event the parties are unable to renegotiate the price.

In Alaska, the local utilities have entered into long-term contracts with local gas producers that use a price index to other locations or products since there are no local spot markets. Among the indices used in these gas contracts are NYMEX natural gas futures, NYMEX crude oil futures, and lower-48 production indices. These contracts have provisions that are designed to smooth the price of gas rather than make them subject to daily or monthly pricing. Some contracts adjust only annually, while others adjust quarterly, based on simple averages of the indices over specified time periods. For instance, some contracts may take a simple average of the index prices over the 36-month period prior to the annual adjustment date. Others may take averages of the indexes over the prior 3-months, and adjust either annually or quarterly. Finally, many of these contracts are subject to price caps and price floors to further limit volatility.

Likewise, international contracts for LNG sometimes contain provisions designed to smooth price volatility. In some Asian LNG contracts, LNG prices are tied to crude oil prices, but do not adjust on a one for one basis. Rather, they use so-called S-curve prices in which the sensitivity of the LNG price to the oil price declines at high and low oil price levels. Thus at high oil price levels, the LNG price will not rise on a one for one basis, but will be less than the oil price (stated on an MMBtu basis). At low oil prices, the LNG price will not fall on a one for one basis and will be higher than the oil price. LNG contract prices also may make use of caps and floors.

These examples suggest the types of non-standard contracts that could in theory be signed in the U.S. They could have fixed-terms with annual inflation adjustments. Or they could be tied to other measures. One could imagine an industrial end-user being interested in a gas contract tied to a price index of its final product (e.g. fertilizer) such that price adjustments would mirror (or netback from) the movements of the final product price. Or, physical contracts could be signed that are tied not to a monthly index, but a simple average of an index over some prior period (e.g., a year or three-years). Complex optionality could also be useful, and is not uncommon – such as look-back options tied to the highest price or to the average price of the commodity over some time interval, rather than the price on the day of maturity. Of course, these types of contracts may face the same barriers that face fixed price contracts generally, including utility unwillingness to enter into them for fear of prudence disallowances.

One other trend that emerged in U.S. gas markets in the past 10-15 years is the use of asset management agreements, in which a gas utility outsources its entire procurement portfolio (gas supply, transport and storage contracts) to an energy marketer in exchange for delivering the entirety of the utility's load requirements at a functionally specified price. The marketer has the ability to design and optimize the supply portfolio (which may not even be known to the buyer) and can earn margins by procuring at an average cost below the contract price under the management agreement while performing these optimization activities. However, these agreements typically index the price of gas to a local delivery market, so in that sense still expose the utility to some price volatility. In principle, there is no reason that terms transferring more risk to the managers could not be sought. In the electric industry, it is now quite common to

outsource load serving obligations to power marketers for fixed, three year prices. Again, the only limit on such arrangements is the creativity and financial tastes of the parties.

## **V. RISK MANAGEMENT PROCESSES AND CONTROLS**

Companies that use hedging instruments must have risk management policies that provide guidelines for the operations and control of the program. These guidelines will typically specify some or all of the following features of the programs:

- Goals
- Targets/Schedules
- Metrics/Reports
- Controls

We discuss each of these features below.

### **GOALS**

Most risk management policies will explain the corporate objectives of the hedging program that will be undertaken. For many electric and gas utilities, the objectives tend to be fairly general statements about how the program will reduce price volatility for end-use customers and increase rate stability, rather than explicit statements about the kind of risk reduction that is being sought and the bounds that are going to be established by the program. Some electric utilities will include meeting budgeted fuel expenses (e.g., in an annual plan) as part of their hedging objectives. Producer goals are more likely to specify cash flow stability at or above levels sufficient to cover investment cost recovery of wells, or protection of cash flows from price declines, as their purposes. End-users who use natural gas as a feedstock input may specify operating margin protection as their hedging goal.

To be operational for hedging management, such general goals need to be translated into numerical constraints on one or more financial metrics which the risk managers are supposed to help achieve. For instance, they may be expected to keep gas costs within x percent or y dollars per MMBtu of some budgeted total or average cost, with a high probability. A utility may have a goal of keeping a typical residential customer's rates to annual changes that are no larger than \$1/MMBtu, or perhaps to keep the maximum bill change per month to within a certain amount, relative to the amounts implicit in the forward curve as of some prior rate case. In addition to goals for gas costs or revenues themselves, there will probably be additional constraints on credit and collateral exposure, from the treasurer of the corporation or division.

### **TARGETS/SCHEDULES**

Once reasonable quantitative goals are specified, it is possible to design and manage a hedging strategy that fulfills those needs. This requires simulation models capable of showing how combinations of open positions and various possible hedges are likely to perform, given expected

market volatility. Such simulations can be used to compare the risk-reduction performance of different strategies that vary the type, timing, and extent of reliance on different kinds of hedges (forwards, options, etc., as described in the prior chapter). These simulations can also be used to anticipate how much credit and collateral exposure could arise, and how that could be dampened with alternative approaches.

Once a strategy is selected, it may be possible to describe parts of it as almost mechanical steps for achieving stated amounts of hedging for specific future periods, by specific dates, with a menu of allowed hedging instruments. These schedules can be quite rigid and prescriptive or flexible guidelines, depending on managerial (and if applicable, regulatory) preferences. For utilities, more prescriptive approaches are generally preferable, so their procurement policies will typically specify the percentage of expected gas requirements or load over some time period that will be hedged. A gas LDC may commit to hedging a certain percentage of its coming expected (“normal-year”) load by a certain point in time (e.g., 50% of expected needs for the coming year will be hedged by July 1<sup>st</sup> of the preceding year). Or it may hedge a portion of only its expected winter requirements (e.g., hedge 70% of expected winter load by July 1<sup>st</sup> in installments beginning 12 months prior to then). Targets that vary by time horizons are a part of many hedging plans, often with an intention to be more thoroughly hedged for near periods than remote ones. This pattern is natural, reflecting both greater uncertainty about future volumes that will be involved and perhaps reduced liquidity in more distant hedges.

One advantage of a more prescriptive, mechanical approach to hedging is that it avoids any tendency towards speculation. Most “commercial traders” (who have physical use of the traded commodity) tend to hedge only for the volumes they expect to use on their own. They do not contract purely for financial motives or in pursuit of speculative gains, even if they are pretty strongly convinced that a forward position is a bargain. This can be especially important for utilities, who may find their fuel costs are disallowed by regulators if there is evidence that those costs were incurred for speculative reasons rather than just for operational risk reductions to protect customers. However, even the policies for utilities are not strictly prescriptive, instead providing some flexibility to adjust the timing and quantity of hedging purchases as long as periodic targets are roughly met. For example, the hedge volume targets might be specified as a range (hedge between 40% and 60% of the coming 12 month expected requirements). Or the policies may state that deviations from plan are acceptable with the permission of the risk oversight committee. For example, a hedging program may be altered in response to unforeseen circumstances (e.g., a hurricane affecting prices). The rules also may allow for either the acceleration or deceleration of procurement of hedging instruments based on historical norms. Thus, an entity may try to hedge to its targets either more or less rapidly if prices or volatility are perceived as being particularly low or high relative to historical levels.

The policies used by other market participants may grant wide discretion as to the timing of hedge implementation and the hedge volume targets. Producers may hedge either a large or small portion of their coming year production based on their market view and perceptions of forward price levels. They are also less likely to follow specific installment schedules.

## **METRICS/REPORTS**

All companies will have some formal, regulatory reporting of their risk management activities through daily and weekly risk reports that are provided to risk managers, an oversight committee, and (less frequently) to executive management. The metrics that are monitored in risk reports can vary in sophistication. Some companies will have relatively simple monitoring reports in which they review hedge positions relative to targets, without any formal monitoring of the exposure of the unhedged positions of their portfolio. They will typically track forward positions and changes in those positions from prior reports. They may also monitor the cost of their hedged positions relative to current spot or forward market prices (and changes in prices from prior reports).

The more sophisticated risk management programs will use formal statistical techniques to measure and monitor the risk of unhedged natural gas procurement portfolios. One of the most widely used measures of risk is called “VaR”, an acronym for “value at risk”. For a utility, this is a measure of how much the unhedged portions of its supply portfolio could change in cost over a given time frame with some stated probability. Some companies also simulate and monitor risk exposures similar to VaR (such as cumulative cash flow at risk, or customer bill at risk) over the next few months, a season, or a year, and they may do so at more than one probability level.

To calculate the VaR, the possible daily change in portfolio value is simulated, based on either historical or market-implied measures of likely volatility for the key inputs (like natural gas prices), their associated correlations if more than one risk factor is involved (such as transactions at more than one location, or both costs and revenues having risk elements), and a distribution of possible next-day values (for the portfolio over the position management horizon) is created. The VaR calculation then often focuses on what change in value has only a small chance of being exceeded – typically a five percent chance of being exceeded is used. This is equivalent to determining the range of values that span a 95% confidence interval for tomorrow’s possible change in the value of the portfolio. A limiting value will be set for VaR based on how other corporate financial objectives are protected by so doing. The risk managers then pursue hedges that attempt to keep the 95<sup>th</sup> percentile of potential changes in value to within that VaR limit.

## **CONTROLS**

The VaR of a portfolio changes over time (daily), as market forward prices and the composition of the portfolio changes. If/when the daily VaR exceeds the VaR limit, the risk management strategy can be accelerated or modified (to add more hedging). Thus, VaR is a sort of barometer for how much variability can arise in the portfolio from day to day and for how well the risk management practices are doing at keeping the daily variability to a financially manageable level. It can also be calculated over other time frames and at other probability levels. In general, a longer time frame or a higher level of confidence both increase the VaR, but not necessarily in some smooth way. It may be that the extreme risks of what could happen in the 5% worst possible outcomes have a different pattern than the risks inside the 95% confidence interval.

While VaR is a useful risk management tool, it will not generally be enough by itself to keep the portfolio on track. Day by day, a portfolio could be kept within its VaR limits but still be becoming steadily more expensive, potentially beyond some point of tolerance. There may be little that can be done about such steady trends, because as described above, hedging cannot be used to “beat the market.” But it is important to keep track of any such persistent drift and to reevaluate the portfolio strategy if the cumulative losses (or gains) become large enough. Typically, a portfolio will be managed to have different thresholds for a worrisome short term (e.g. monthly) movement vs. a longer term (seasonal or annual) cumulative movement. The thresholds of review are called “stop-loss” limits. Stop-loss limits are designed to limit cumulative losses in the value of a portfolio that may occur over a monthly or annual basis as a result of fundamental price movements that result in losses that are realized over extended periods. If the specified monthly or annual thresholds are reached, it provides a signal to management that additional actions may need to be taken (e.g., potentially entering into additional hedge transactions). These limits, coupled with VaR monitoring, help to discipline the freedom to simply buy opportunistically. That is, this helps to avoid the danger of deferring hedges when prices are rising (because it seems that prices are unfavorable relative to past levels) when risks may also be rising (hence deferring purchases could result in wider VaR exposure).

VaR calculations are widely used in risk management to keep control over how much a portfolio of contractual and security positions could change in value over a given time interval. However, VaR has come under some fire as an inadequate method for measuring and controlling risk, especially for energy commodities like natural gas and electricity. The basic complaints about VaR generally fall into three categories: accuracy, sufficiency, and over-reliance.<sup>9</sup> Each of these concerns is valid and important, but they are not sufficient for rejecting VaR or its conceptual cousins, such as Cash Flow at risk (CFaR) or VaR measured over longer time frames (such as TEVaR, or time-to-expiry VaR).

A VaR simulation is only as good as the quality of its inputs, which include probability measures for the potential behavior of the components and their correlations. These parameters can come from historical data, in which case they do not have to assume a particular type of price distribution (i.e., data need not be treated as being normally distributed), and correlations among components can be as complex as they actually were in the historical period providing the source data. In fact, those correlations do not even have to be measured or understood when historical sampling is used. But if historical data is not a good proxy for what is likely to occur in the future, then the associated VaR will be misleading. So an alternative is to infer volatilities from forward traded products. The mathematic calculations for doing this are not difficult, and brokers will often quote them for interested traders. However, there is typically an assumption that future prices are normally distributed. As described earlier in this report, energy prices tend to be skewed, with the possibility of rare but occasionally very high prices.

---

<sup>9</sup> A strong and widely cited criticism of VaR appeared in the *New York Times Magazine* in January 4, 2009, alleging that excessive and naïve reliance on VaR had contributed significantly to the financial crisis we are now enduring.

Correlations among cost and revenue sources are also needed to simulate distributions and calculate VaR, but they are generally not provided by brokers. Unfortunately the needed correlations can be very numerous and extremely difficult to estimate, as they may vary by time of year and by horizon of contract. For instance, daily gas and electric spot prices may be fairly weakly correlated, and differently in the summer and winter than in the fall and spring, while longer term gas and electric contracts may have higher correlations. Since the VaR calculation will reflect whatever assumptions are made, it may understate true risk if there are elements of the problem that are mis-specified or not captured.

One way of testing these concerns is to backcast the daily VaR estimates against actual value movements in the associated portfolio. If a 95% daily VaR is being estimated fairly accurately, then over a long enough time period (e.g. a whole year), about 95% of the daily actual value changes should be less than or equal to the calculated VaR (and greater than the calculated VaR only about 5% of the time). If this is not the case, the VaR estimation parameters are probably not sound.

A second concern is that there may be two kinds of special events that simply are not likely to be captured by almost any variant on a VaR calculation, even with careful statistical adjustments: rare, very high-priced events and “liquidity black holes”, or times when it is simply very difficult to find enough counterparties to move a large position. A VaR is a threshold of likely value movement, but it does not tell how much the portfolio could change in value if it goes beyond the threshold. If a hurricane is unexpectedly damaging, there could be a gas price spike that is very large and threatening to your financial health, even if it is occurring no more often than the VaR would predict. One way to evaluate risk exposure and potential responses to these kinds of extremes is to construct a simulation that mimics a few specific events that might have such devastating effects. This is called scenario analysis or stress testing. This obviously also requires its own assumptions that may prove to be inaccurate, but at least you will have evaluated whether you can withstand circumstances that are as harsh as you care to worry about.

A third common complaint about VaR is that its formality and seeming rigor can lead to a kind of complacency that risk is fully under control. In fact, this is not a complaint about VaR but about analytic risk management, and it probably has some truth to it. There is a tendency in many industries to believe a result simply because it is the product of sophisticated and detailed modeling analysis. (Production costing simulations for electric companies sometimes have this kind of veneer of credibility, even if they are populated with poor assumptions or dramatic oversimplifications of the market.) Unfortunately, there is no real cure for this problem! One is certainly no farther along in managing risk effectively by not quantifying it. What is required instead is appreciating that risk management quantifies “known unknowns”, but there may well be “unknown unknowns” or circumstances that are so non-standard that they are neglected in evaluating risk, even though they could be important. It is very useful to constantly challenge your basic, implicit assumptions that the overall problem has been specified properly in the first place and that your data is an accurate foundation for what could actually happen. Many risk management disasters have occurred when there was insufficient skepticism about parameters that had departed from their normal ranges, but were not perceived as flawed in a timely fashion.

## LIMITATIONS IN MANAGING GAS PRICE VOLATILITY

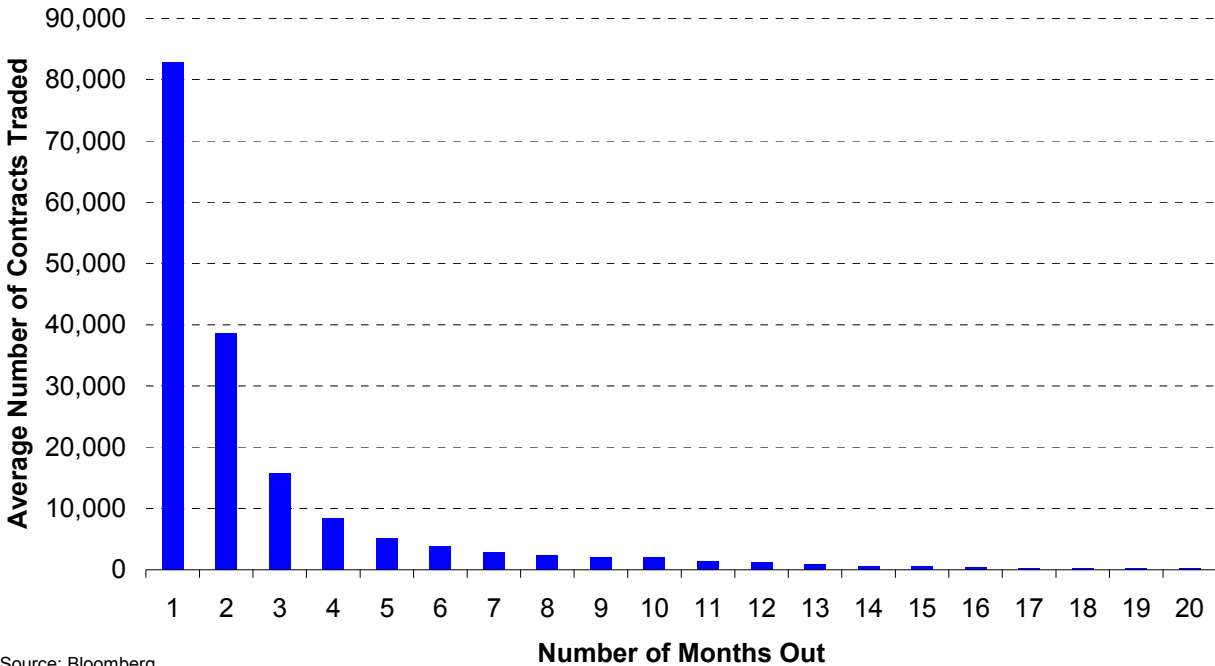
Hedging programs will not generally remove all exposure to gas price volatility, nor should gas market participants seek to remove all price volatility. Even a very sophisticated and elaborate hedging program cannot withstand the forces of long-term, fundamental change in the industry, for several reasons. First and foremost, the available hedges are not “complete,” meaning they do not span all the possible risk factors and contingencies that could alter future needs or the opportunity costs of covering those needs. In particular, hedges are not generally available for distant time periods in the future, so the best that can be done to manage the changes in costs that arise over a long period is to use an imprecise physical hedge (such as owning production resources) and gradually fold near- to mid-term financial hedges into the portfolio. This will not eliminate the eventual changes in cost, but it will spread their recognition over longer periods of time. Second, it is impractical to attempt to eliminate all risks, even if it was possible in principle to do so. Hedging is a time-, money-, and human resource-consuming activity that must be balanced against other uses of those assets and capabilities. As a result of practical tradeoffs, some items will remain unhedged and others will be simplified or ignored in forecasting and risk simulation models. This creates inevitable estimation errors and gaps in hedging coverage. Third, the hedging process involves implicit assumptions that the current best estimates of riskiness and the relationships among key factors (e.g., based on past volatility or current market-implied volatilities and correlations) will in fact describe the future, so that one kind of risk can be predictably used to offset another. However, the world is not always so well-behaved and cooperative. Market parameters change in unforeseen and unforeseeable ways, invalidating prior hedged positions. More specific examples of how these limitations on feasible hedging arise are discussed below.

### *Liquidity issues*

Most of the standard hedging wholesale contracts are actively traded in the near-term (up to one to two years out), but are much less frequently traded in the more distant, years forward. This can be seen in the Figure 17 below, demonstrating that most of the trading of NYMEX gas futures contracts is for the month-ahead (“prompt month”) forward contract.

Figure 17

## Average Number of Gas Contracts Traded By Expiration Date



Source: Bloomberg.

Note: Average number of contracts traded is over the 2008-2009 time frame.

In 2008-2009, the average number of contracts traded for the prompt month contract was roughly 80,000 contracts on each day. The traded volume declines substantially for the two-month ahead forward contract, but is still significant with roughly 40,000 contracts traded each day. The volume of contracts traded for the 12-month and 20-month forward contracts are quite small by comparison, indicating much lower trading liquidity of those contracts. More complex and specialized derivatives, such as options and weather protection, become illiquid even sooner than forwards.

Illiquidity impairs hedging in several ways. It can mean there is no hedging contract available, or at least no standard one that can be evaluated simply in terms of how its price compares to other similar products. Or it can mean there is no buyer available to allow you to get out of a contract, if/when it becomes unattractive to continue holding. The only way to liquidate a position may be to reduce its price well below what seems to be its intrinsic value, in order to find a buyer. Illiquidity may also be felt as high bid-ask spreads (again raising the costs of moving in and out of positions) or substantial transaction costs and risk premiums. All of these barriers and frictions tend to make hedging more difficult and less likely to succeed. As a result of these limitations, many gas market participants may need to wait to hedge upcoming expected volumes, which can result in hedges not being undertaken until after possible market shifts have occurred that cause unforeseen increases in gas expenses.



### *Credit and collateral costs*

Hedging programs often result in offsetting costs and risks. Extensive hedging for distant future period creates competing costs and risks. In particular, a longer and larger forward position entails both credit and collateral risks that can become prohibitive. When a company chooses to lock down future prices (especially far in advance of delivery), it becomes more vulnerable to intervening price changes and resulting financial performance concerns about (and from) the counterparty to the contract. These concerns arise from the possibility of supplier failure and/or the consequences of mark to market accounting and cash collateralization obligations for positions that become “out of market.”

For example, a fixed price purchase that becomes highly valuable in a rising price environment exposes the buyer to the credit risk of the selling counterparty. If the counterparty fails to deliver at the committed price, the buyer is exposed to having to replace the purchases at a higher, unexpectedly unhedged price. Conversely, if the market price for replacing that contract should drop significantly, the seller may become skeptical of the buyer’s ability or willingness to consummate the purchase, so it may insist that the buyer post cash in an escrow account sufficient to cover the difference between the quoted price in the contract and the prevailing market forward price. For a large, long term contract, this can potentially be very large amounts of cash. Even if this collateralization is avoided, the imputed cost of debt from long term forward commitments to purchase gas at fixed prices may raise the cost of long-term forward hedging. Thus, there is “no free lunch” in hedging or anywhere else. At some point, it is better to leave some of the future unhedged rather than have to face all of the attendant financial performance burdens and risks.

### *Regulatory barriers and risks*

There are substantial regulatory barriers that limit the amount of volatility reduction that can be achieved or will be sought by hedging programs. One is that regulators might perceive that it makes sense for regulated utilities to leave portions of their procurement portfolios unhedged, so that customers face a somewhat more efficient price (that reflects shifting market conditions) and so they can benefit in the event of declining prices.

Likewise, the use of long-term fixed price natural gas contracts would seem to have a natural role in utility procurement portfolios, given the general perception that customers do not like volatile bills. However, customers also do not like to have steady bills that turn out to be much higher than the market, raising the risk that a set of forward positions will be challenged in hindsight as having been imprudent. Utilities will be unlikely to enter into such contracts unless they are approved and deemed prudent in advance, but regulators are often not willing to grant such an advanced prudence determination, making the contract too risky for the utility.

### *Budgets for hedging costs*

Strict budgets on hedging transaction costs can limit the use and effectiveness of some risk management strategies. As discussed earlier, call options are like an insurance product in that they can pay off at an extreme, but they require the up-front payment of an option premium in

order to get the benefit. These premiums can be costly, especially for strike prices that are close to the expected future value of natural gas. Sometimes corporate treasurers (or utility regulators) will set budgets that limit the degree to which option premiums can be incurred. For example, they might have a rule that no more than 3% of expected annual gas costs be spent on option premiums. The impact of these budgets can limit the use of call options, perhaps forcing less hedging, or use of other hedging with lower direct costs (such as options that are way out of the money, or wide costless collars). It is important to remember that efficiently priced hedges do not change the expected costs of gas, so putting a constraint on upfront transaction costs does not lower the overall expected cost of the program in any way. Rather, it just limits the menu of available hedges and the resulting risk shaping that is possible.

### *Ex post regret fears*

A psychological or cultural barrier to effective hedging can be the fear that the hedged positions will turn out to be more expensive (if they are costs) or less valuable (if they are revenues) than would have occurred without hedging. In some cases, this can lead to limited hedging, or to imitative hedging that is based more on similarity to other companies than on achieving specific risk reduction goals of the company. In general, one cannot achieve both actual ex ante risk reduction and avoid ex post regret. One induces exposure to the other. It is important to be clear in setting the original goals for the risk management program to sort out this tradeoff.

## **VI. COMPARISONS OF INDUSTRY HEDGING PRACTICES**

In this chapter, we present some short case studies that reveal very different motives and strategies for coping with gas price risk across various sectors of the gas industry. We examine gas distribution utilities, electric utilities or generators with a substantial fleet of gas-fired power plants, large and mid-sized gas producers, and industrial gas-feedstock users.

### **GAS DISTRIBUTION UTILITIES - HEDGING FOR CUSTOMERS WITH PHYSICALS AND FINANCIALS**

Most gas distribution companies (LDCs, or Local Distribution Companies) hedge a material portion of their gas supply needs, and have been doing so for a decade or more. In part because of public disclosure of regulatory information, and regulatory comparisons of best practices across the industry, there is a fair degree of uniformity in the hedging strategies used by gas LDCs.

The gas supply planning problem for a gas LDC is to procure a reliable supply of delivered gas at reasonable prices from upstream wholesale sellers of gas, which typically also involves a portfolio of firm pipeline transportation and storage contracts. The wholesale sellers may enter long-term (several-year) commitments to supply specific quantities of gas, but those are almost always priced at bid-week monthly index prices.

Most gas LDCs have regulatory cost recovery mechanisms for their upstream gas costs that largely inoculate the LDC from financial exposure to the seasonal and idiosyncratic variability of monthly (and other, e.g., daily) gas costs they incur. This is important, because the commodity portion of an LDC's costs may be 2/3 to 3/4 of the total. Failure to recover even a few percent of such costs could be a huge blow to net income, which may be only a few percent of revenue. There are many forms for these gas cost "adjustment clauses" ranging from pass-through almost when incurred to annual lagged amortization of cumulative variances from a previous allowed price per therm. While this might seem to make hedging unnecessary for the financial health of the LDC, in fact this ability to pass on costs to end-use customers is reliable only to the extent the incurred gas commodity costs are deemed prudent and reasonable. There are no precise, quantitative definitions for those criteria, but they are generally taken to mean that the resulting gas prices should not deviate so sharply from previous rates as to cause economic hardship for customers, and that any increases should not be the result of indifference to opportunities to hedge that might have buffered some of the variance. Likewise, if wholesale market costs are falling, it is politically attractive to the LDC to have its costs of gas also falling somewhat, so that customers see a timely benefit of the reduced upstream prices. Failure to follow market prices down may also cause a risk of disallowance.

These customer needs and regulatory expectations for well-behaved delivered gas prices have lead most LDCs to manage their gas roughly as follows:

- Use all the available storage to cover as much as possible, perhaps 1/4 to 1/3, of winter peak needs, priced to customers at the weighted average of (mostly summer-procured) cost of gas plus the demand charges for storage.
- Hedge much of the remaining winter baseload requirement via forward purchases made in regular installments beginning a year or so ahead of the delivery period – a process sometimes referred to as “dollar cost averaging.”
- Leave the more uncertain, non-baseload, non-storage quantities unhedged, to be procured on a monthly or daily basis at prevailing spot prices.

This approach has two key benefits: 1) By leaving some supply “open” (unhedged), there is assurance that customer prices will directionally match upstream wholesale price changes, albeit with reduced variability, and 2) by hedging winter baseload via regularly scheduled installment purchases, no efforts are made to “time the market” (i.e. to try to buy more gas when the forward price seems opportunistically low). This avoids any exposure to the allegations that the company was speculating, or simply should have bought more at some other, even (ex post) more opportune time.

Some gas utilities go a bit further. Some use call options or collars to manage their risk within a bracketed range. This creates a situation where upside costs are capped, while downside cost movements are at least partially open. Some use “accelerators” and “decelerators” to adjust the timing and size of their installment purchases. The idea is that forward prices are compared to recent past variability of available prices. If the currently available price is on the low side of prior trailing prices, then there may be a motivation to increase the current procurement. If the current price is high compared to trailing prices, perhaps it is best to wait a while and see if the market cools off. Implicit in this practice is the belief that gas prices are mean-reverting and from what is called a “stationary distribution” i.e., they arise from market conditions that are centered on the same long run average and they vary about as widely in the future as in the past. In periods of fairly steady supply and demand conditions, this may be reasonable, but it obviously is not a requirement of the wholesale gas market, and it may not be its most common state. Certainly the past ten years of gas prices have suggested that price formation was occurring quite differently from time to time. When that is the case, it is possible to get burned by acceleration and deceleration rules. In particular, if either or both the long run cost or risk of the market are rising, then a deceleration signal may be sensed precisely when more and earlier hedging (i.e., accelerating) would be the better strategy.

While the majority of gas utilities use a hedging strategy of the type just described, it is fairly uncommon for those same utilities to use formal measures of risk reduction to monitor, control, and evaluate their hedging. That is, they do not generally forecast the future range of gas costs per therm, or bill per customer, that is likely to ensue from their strategy, in order to make sure the standard deviation is within some tolerable bound, nor do they compare such cost exposure ranges across alternative strategies. In essence they have adopted risk-reduction strategies, not

risk-management strategies. So far, this has not been a problem for most of them, in terms of demonstrating the prudence of their procurement. However, this lack of risk metrics leaves them vulnerable to potential regulatory criticism that they have not adapted their strategies to shifting circumstances. A procurement strategy designed and monitored to keep future costs within a forecasted range of future average costs would be less vulnerable to hindsight criticism and possible disallowances.

Some utilities evaluate or demonstrate the benefits of their risk reduction strategies by comparing realized costs to the costs that would have occurred had they not hedged at all, i.e. by comparison to monthly spot prices. Over many years, this can be an informative demonstration of how the strategy is performing, but over any given recent past, this can be a very misleading test. In particular, it is very likely that spot gas prices will occasionally be much lower, and possibly even less variable (though that is quite unlikely), than the actual seasonal costs under a partially, progressively hedged portfolio. In such cases, a naïve backcasting test invites cost disallowances and/or undue criticism of the hedging strategy.

#### **ELECTRIC UTILITIES - HEDGING COMPLEX LOAD FOR GAS-FIRED GENERATION**

Many integrated electric utilities purchase large quantities of natural gas to fuel the gas-fired electric generating stations they own and operate to serve native load requirements. These electric utilities face a problem similar to that of gas LDCs – obtaining cost recovery for variable power supply costs (often largely fuel, including gas) that are in principle passed on to customers, but only if prudently incurred. But unlike a gas LDC, an electric utility’s gas supply needs are highly erratic, varying daily according to whether gas-fired power plants are the most economical to operate vs. other types of generation or open market purchases of wholesale power, and according to shifting electric load shapes, transmission constraints, and reliability considerations. Electric utilities are also likely to contract for firm transportation and storage as part of their supply portfolio.

The gas supply contracts between the electric utilities and upstream sellers are typically multi-year commitments to supply a portion (usually expected baseload quantities) of their gas supply needs, and these are usually priced at bid-week monthly index prices. Electric utilities are also frequently active participants as both buyers and sellers in daily gas markets to serve the more uncertain aspects of their load. Daily market purchases and sales allow the electric utilities to swing generation up or down to handle unexpected variations in weather and load. These quantities of gas can be a significant portion of their total needs, but cannot be accurately forecasted until only a few days or even hours before it will be used. Such gas will be obtained in daily or intraday markets, or taken from swing contracts on pipelines against more stable monthly average volumes.

Most electric utilities have fuel adjustment clauses that allow them to pass on to their customers the gas costs they incur as fuel for electric generation. As is the case with LDCs, there are many forms for these “adjustment clauses” that vary the speed and ease of pass-through for incurred fuel and purchased power costs. State laws may also impose requirements on the electric utilities to procure power on a least-cost and least-risk basis – typically without clarification of how those two goals are to be evaluated or traded off, if there is a conflict.

Most electric utilities hedge some portion of their expected gas supply requirements, but cannot hedge all of it because of the extreme uncertainty in when and to what extent the peaking requirements will arise. They also have to consider how their gas procurement and hedging practices interact with their opportunities to hedge wholesale power purchases and sales, which are often the alternative to using their gas fired generation. Thus, they tend to be concerned more about hedging the “spark spread” between the value of gas as converted to electricity in a combined cycle baseload plant, or in a peaking combustion turbine plant, vs. the volatility spot price of power. If the burned gas produces electricity more cheaply than the wholesale power market is clearing, then the power plants should run and produce more, if possible, than the immediate needs of the electric company’s own customers. Profits from the excess sales can be credited back against customer fuel costs, for a net reduction. If the spark spread is negative, with power cheaper than gas generation, then the utility should just purchase what it would otherwise generate with gas, up to its native load demand requirements.

This means that an electric company’s demand for gas is a complex function of both gas and wholesale electric costs, so both must be forecasted in order to estimate likely volumes. Complex system simulation models called production costing models that simulate large portions of the electric network in the entire United States are used for this purpose. This creates fuel requirements and budgets for future months and seasons, which are then hedged according to how confident the utility is of the underlying volume. Typically, the volumes forecasted for use in new, baseload gas plants like efficient combined cycle (CC) units are fairly predictable (tending to be most needed in the summer), so those volumes are mostly hedged with forward purchases made a few months or even up to a year or so in advance. Volumes are mostly hedged for the current year, in large part to try to keep actual costs in line with beginning of year budgets, though a declining portion of second- and even third-year baseload needs may also be purchased forward in installments.

The rest of gas usage is determined in short term operating decisions about the most economical scheduling and dispatch of units used for short periods, perhaps only a few hours a day in perhaps 30-50% of the days of the year. Their needs may not be hedged at all, or if so, may be hedged with option or forward contracts entered only a few days before usage.

Even if a utility has hedged its gas needs at an attractive price, that price will not determine whether or not its gas plants are actually used. Instead, the usage of flexible power plants is based on the relative cost of each type of plant when burning fuel that is priced at current, short term rates. If current spot prices of gas are high and there are slack generating resources as alternatives sources of power, it may be more economical to burn other fuels and sell the gas back to the gas market itself. This is a very common practice in the industry, which results in lower overall costs, but less volume certainty for gas usage.

Many generators in the electric industry are no longer affiliated with a regulated utility, and they have no obligation to serve, no native load, and no automatic adjustment clause for recovery of their fuel costs. They are said to be “merchant generators”. However, the operating decisions that determine how much gas they will need for their gas CCs and peaking stations occur in exactly the same way as a vertically integrated utility, regardless of organizational structure. So they have the same volume complexity and concerns about the spark spread. However, they may

choose to own only baseload gas plants as one way to reduce risk, and then they may hedge both their power sales and their gas purchases, in order to lock down more stable operating margins. This can be quite important for their ability to service the large amounts of debt typically involved in financing the construction of a power plant.

#### **GAS PRODUCERS - HEDGING TO PROTECT DRILLING ECONOMICS AND CASH FLOW**

The use of hedging instruments by natural gas producers varies significantly by producer. While some gas producers do not use hedging much at all (except perhaps in limited circumstances, such as projects with peculiar risks), other producers make substantial use of hedging tools as a key part of their overall strategy. Whether and how hedging is used by a gas producer is a function of the producer's size, diversity of operations, and financial strength.

It may seem counterintuitive that some producers make heavy use of hedging while others barely do it at all. But this is not that surprising in at least two key respects. First, as discussed earlier, one of the key principles of risk management is that hedging does not change expected outcomes. Therefore, some producers may feel that hedging programs may lead to gains in some years and losses in other years, but over the long-term, there will be no net gain from hedging and average prices will reach the same financial end without all the complexity. This requires confidence that the extreme possible outcomes along the way are tolerable, which tends to be true of larger companies rather than start-ups or niche players. Second, risk management should be undertaken to solve a problem that is created by extreme variations in prices. For instance, some producers have more debt than others to service per MMBtu extracted and sold, especially if they have expanded recently or rapidly, while others may have large fields and considerable flexibility to adjust their rates of production and expansion to respond to shifting prices for gas, and so be relatively secure despite little hedging.

We describe these different types of gas producers and their different approaches in more detail below.

#### **Major Integrated Gas Producer**

Major oil and gas companies that are natural gas producers may not need to hedge their gas price exposure due to their financial strength and diversity in operations. In addition to their gas production assets, these companies are frequently large oil producers, and many own refineries (and produce refined products that are correlated with the price of oil and to a lesser extent, the price of gas).

Some of these companies have policies of remaining exposed to commodity market prices (both oil and gas) and therefore generally do not hedge their natural gas production except in limited circumstances. Their view is that their investors generally desire the exposure to commodity market prices that is inherent in their business and that this kind of performance is understood and reflected in their stock price. These views may have been informed by past experience with hedging programs that were unsuccessful and resulted in shareholder dissatisfaction. It is sometimes observed that investors do not seem to applaud successful hedging, but they do seem to resent unsuccessful hedging.

These companies also believe that they do not need to hedge due to the size and diversity of their strong balance sheets, which makes it unlikely that extreme movements in natural gas prices would lead to any kind of financial distress. Moreover, they have the ability to react to significant natural gas price swings, ramping up production if prices increase and shutting in production of marginal wells and slowing expansion if gas prices fall dramatically. Another reason for the lack of large-scale hedging is that most of their customers or counterparties generally will not want long-term fixed price positions. For instance, some gas-fired electric generators face fairly erratic variation in when and to what extent they will be dispatched, resulting in significantly uncertain volume requirements that are difficult to forecast and hedge. The diversified nature of large, integrated oil/gas companies, including their oil production and refining operations, make natural gas price fluctuations less of an issue for them relative to a small or mid-sized natural gas producer that only focuses more narrowly on natural gas.

Nonetheless, the large producers do enter into some short-term hedges related to specific transactions and for some price management services they offer in products customized for some of their customers. They do tend to measure and monitor the VaR associated with these activities, even though they are fairly limited.

Even though large producers may not hedge their gas production extensively, it is worth noting that they do believe their industry is exposed to important, longer-term risks, especially related to potential climate policies that are adversely affecting their ability to plan and manage. More generally, they believe the lack of clarity on climate policies is creating uncertainty that may undermine the overall development and demand for natural gas, especially if coal and renewable interests receive more favorable treatment in future legislation. This might have perverse environmental consequences of favoring less clean fuels, or energy supplies that cost much more per ton of carbon avoided than increased use of natural gas might entail.

### **Mid-Size, Independent Gas Producers**

Mid-size production companies on a growth path tend to rely significantly on hedging instruments to create cash flow certainty, especially if they have relatively leveraged capital structures (with high debt ratios). These companies use hedging instruments as an integral part of their overall strategy to maintain and grow their natural gas production. These producers tend to be in a fundamentally different position than the large, integrated oil companies. They tend to have smaller balance sheets than the larger integrated oil and gas companies and have more debt as a percent of their total capitalization.



The mid-size producers use hedging instruments to achieve cash flow stability from existing production and/or to protect against downward movements in gas prices (that would be experienced under indexed contracts). Achieving such cash-flow certainty makes it more likely they will be able to sustain production (and not have to shut-in production) in the face of declining market prices, and they will be in a position to fund further reserve development and production growth (and possibly improve their access to capital). It also provides some assurance that they will not run into cash flow constraints that impede their ability to meet debt obligations (which can help credit ratings in some instances). In some cases, lenders might require mid-size producers to hedge a portion of their production, though there is some ambivalence about this, because of potential risks of difficulty in covering a net short if production is lower than expected.

The risk management activities of the mid-size producers tend to be done on a centralized and aggregated basis (rather than by division, project, type of gas, or region of the country) and with the direct oversight and involvement of senior management. Most of these producers use hedges primarily to cover expected production and lock in margins that exceed the full cost of production, including capital recovery. These producers tend to be less prescriptive and more dynamic in their approach to hedging than other market participants (e.g., gas and electric utilities). That is, they are less likely to follow rigid hedging installment schedules that dictate certain milestones must be met at certain time periods. They also do a significant amount of “fundamental analysis” of gas supply and demand market conditions, such as monitoring rig counts, LNG imports, storage levels, general supply and demand conditions, and so on. They respond with accelerated hedging implementation if they feel it is warranted based on fundamentals, and this has helped some of them obtain substantial margins over production costs even as spot prices have fallen significantly in the past year. Thus, unlike electric and gas companies, the mid-size producers may view themselves as having more flexibility to pursue dynamic hedging programs that are influenced by their market view.

Mid-size producers typically use the full variety of hedging instruments including fixed-for-floating swaps, collars, call and put options, and basis swaps to protect against locational basis-price differences. They typically hedge over a relatively near-term horizon, with most hedges covering one to three years forward (and typically hedging larger percentages of the coming year production and lower percentages in years 2 and 3). While hedges are possible as far out as five years, the use of hedging instruments becomes less likely past three years forward because of liquidity issues (with relatively little trading of most hedging instruments beyond 3-4 years). Some producers limit their out-year hedging so they can adjust their overall business strategy and hedging approaches after a three or four-year period (a window in which fundamental supply and demand changes are more likely). While some producers would consider much longer term (10+ year) physical supply contracts with utilities, most feel that such arrangements are difficult to achieve due to credit issues, and constraints on what prices utilities are able or willing to consider relative to the premiums that would be necessary under such agreements.

Credit issues are also an important factor in the implementation of hedging programs by mid-size producers. The use of hedging instruments exposes producers to the credit risk of their counterparties. Producers attempt to limit this credit risk in various ways, such as limiting trading to creditworthy counterparties and trading with many counterparties to limit exposure to any single counterparty. Some producers have entered into multi-party hedge facilities in which multiple counterparties have agreed to jointly provide derivatives trading capacity in exchange for pledged collateral of natural gas reserves. These agreements expand the amount of production that can be hedged and the time horizon of hedging, and improve liquidity. The counterparties' obligations are also secured by cash instruments and these agreements net offsetting positions against each other.

#### **INDUSTRIAL END-USERS – HEDGING GAS USED FOR FEEDSTOCK AND ENERGY SUPPLY GIVEN CONSTRAINTS ON FINAL PRODUCT PRICES**

The degree to which industrial end-users are hedging natural gas costs is less clear than for other sectors due to the diverse nature of the industrial sector and the differing circumstances of specific industrial users. However, as a general rule, many have significant energy and commodity feedstock costs, face international competition, and have mostly industrial and commercial customers that are price-sensitive. Thus, they have very complex business environments to manage. Some appear to make substantial use of hedging tools while others have limited or no energy hedging, though they may hedge other risks such as foreign currency exposure. In general, these industrial hedging programs have the objective of protecting margins and overall net income in circumstances where there is poor correlation between gas input costs and final product prices. Figure 18 below gives a simplified view of how a handful of industrial gas users deal with their exposure to natural gas costs. The remainder of this section describes a case study of an industrial end-user that faces problems that are likely to be common to many feedstock users, but we cannot say that its solutions are equally widely used.

**Figure 18**

**Gas Use & Hedging by Industrial Feedstock Companies**

<b>Company</b>	<b>Gas Commodity Exposure?</b>	<b>Commodity Hedges?</b>
<b>Air Products and Chemicals, Inc</b>	<ul style="list-style-type: none"> <li>- Gas used as an energy source, and is one of the largest cost components in the production of energy</li> <li>- Gas used as a feedstock for hydrogen and other gasses</li> </ul>	<ul style="list-style-type: none"> <li>- Mitigates these risks through long-term pass-through contracts to customers</li> <li>- Limited commodity swap contracts to reduce cash flow exposure to the price of natural gas relative to oil-based feedstocks</li> </ul>
<b>Dow Chemicals, Inc.</b>	<ul style="list-style-type: none"> <li>- Gas for steam &amp; energy</li> <li>- Gas for feedstock</li> </ul>	<ul style="list-style-type: none"> <li>- Much of first two-year needs covered with forwards &amp; swaps</li> </ul>
<b>DuPont E.I. de Nemours &amp; Co.</b>	<ul style="list-style-type: none"> <li>- Gas used in agriculture and nutrition, performance chemicals, and performance materials</li> </ul>	<ul style="list-style-type: none"> <li>- Commodity price risk management programs that generally lie within the next two-year period</li> <li>- Company partly hedges natural gas with fixed swaps and options</li> </ul>
<b>PPG Industries Inc.</b>	<ul style="list-style-type: none"> <li>- Gas is a primary energy cost</li> <li>- Gas also used in commodity chemicals and glass businesses</li> </ul>	<ul style="list-style-type: none"> <li>- Hedge 25 - 30% of the coming-year of natural gas, often with swap contracts</li> </ul>
<b>Eastman Chemicals Co.</b>	<ul style="list-style-type: none"> <li>- Gas is a major raw material and an energy source in the manufacturing process</li> </ul>	<ul style="list-style-type: none"> <li>- Options and forward contracts to manage propane, gas, &amp; ethane costs</li> </ul>

Source:  
10-K's of the respective companies

An industrial end-user of gas purchases very large volumes of natural gas for two main purposes: (1) to produce steam and electric power used in its manufacturing plants and (2) as a feedstock for chemical products it manufactures. These two types of expenses may be comparable in magnitude. The company has manufacturing facilities both in the U.S. and overseas and is a consumer of natural gas in both locations. Natural gas costs represent a significant percentage of the company's overall costs and the products derived from gas are a significant percentage of the company's annual sales. The company sells its final products both domestically and overseas and faces global competition. The company also uses other fuels as feedstock in its manufacturing processes, including naphtha, ethane, and propane.

Global competition in sales of final products presents difficult challenges in the company's procurement of natural gas in the U.S., because increases in U.S. gas prices generally cannot be passed through in the final product prices. First, its overseas competitors may not have incurred a comparable increase in their gas costs, since gas prices are not closely integrated internationally nor are gas contracting and pricing practices similar. In some countries, national energy policies or support for key industries may reduce their exposure to gas risks faced by U.S. companies. Second, the company's customers also tend to be industrials facing significant international competition in the products they sell, so they are very price conscious. Were the company to attempt to raise its final product prices as a result of increasing gas costs, it would be likely to lose market share. This inability to pass through gas cost increases puts such industrial end-users in a substantially different position than other gas market participants, who often do have some ability to pass through increased gas costs in their final product prices (especially a gas LDC or a power producer).

The company has several hedging programs that are managed separately for lines of business that rely on different fuels/feedstocks (e.g., a unit for natural gas, a unit for ethane, etc.). Risk management for these separate fuels and final products are not pooled at the corporate level, because their risk characteristics are different enough that there would be no obvious synergies from pooling, except diversification – but this benefit is already enjoyed without co-managing their hedges. So, the individual business units make risk management decisions for their respective fuels with some corporate oversight of their approach to hedging activities. Accordingly, the company keeps track of different VaRs and VaR limits for the different fuels, and products that it manages.

The company only hedges its natural, commercial exposure to natural gas (i.e., its natural gas requirements for its business); it does not use derivatives to take speculative positions based on market views regarding the different fuels in which it participates. In addition, its customers generally do not enter into long-term fixed price contracts to purchase its products. Thus both the prices and quantities of final products sold are quite cyclical both with respect to economic conditions and production capacity within its industry.

The company uses primarily NYMEX futures contracts to hedge both its energy and gas feedstock purchase requirements over the coming 18-24 months, but most of its hedges are for the coming 12 months, again in part due to the horizon over which it may have forward sales commitments or reliable predictability. Its gas-fired, steam-generating power plants run at close to flat round-the-clock utilization levels, so the required gas quantities are level, easy to anticipate, and easy to hedge. Feedstock volumes are a bit more episodic but not materially variable over moderately long periods of a few weeks or months, so that they can be hedged fairly tightly. The company hedges a large portion of its natural gas requirements, but not 100%, mostly within the coming two years. This horizon is partly driven by the reduction in liquidity in forwards and futures thereafter, which could be a factor if it should become necessary for the company to close out positions due to declining product sales. The company's hedging of substantial levels of its gas requirements creates credit and collateral requirements that are significant.

The company noted the fundamental mismatch between using hedges for a two-year forward period versus the manufacturing plant investments it needs to make that are long-term (20+ year investments). Notwithstanding its concerns about more controllable long term costs, the company has not considered making investments in natural gas reserves or production facilities as a longer-term hedge. Gas field operations are considered too foreign to its business culture and expertise.

The increase in volatility experienced in the 2000-2010 period created substantial difficulties for this company unlike the previous decade when gas prices were relative low and more stable. Specifically, the company shut down some of its U.S. plants and made investments in overseas facilities instead. It believes uncertainty in U.S. natural gas prices continues to favor investment in overseas facilities. Even with the recently lower U.S. gas prices that have resulted from shale supplies, the company is concerned about gas price volatility, especially given uncertainty in climate legislation that could lead to increased natural gas demand in the electric power sector or for natural gas vehicles. The company believes that overseas production facilities will not be as exposed to the same degree of price volatility as is faced in the U.S., in part because of regulatory and governmental policies overseas that are designed to limit price volatility and to attract industrial companies for the purpose of job creation. The company noted that U.S. gas producers will not offer non-standard, long-term fixed or smoothed pricing terms for natural gas, such as cost-plus formulas or indexation to producer prices, perhaps because they are facing some of the same long-term anxieties about energy regulatory policies.

## VII. CONCLUSIONS AND RECOMMENDATIONS

Natural gas has clearly been more volatile in the past few years than in the late 1980s and 1990s, and this recent pattern may be the more normal state of affairs. Over the same time as gas price risk was increasing, the extent and sophistication of gas hedging practices also increased throughout the industry. Many market participants—especially electric and gas utilities, and mid-size gas producers—have embraced the use of hedging instruments over the past decade. Electric and gas utilities have adopted hedging programs to manage price volatility for at least the baseload portion of their needs on behalf of their customers (i.e., to avoid the risk of disallowances that might be imposed without hedging). Mid-size gas producers use hedging instruments to manage cash flow for operations and expansion and to ensure debt-service coverage. Some market participants—especially large, diversified gas producers—have decided to mostly forego the use of gas hedging instruments, except where it helps them offer a customized service to particular buyers, since hedging is not really necessary for them given their financial strength. Finally, industrial gas feedstock users face extremely complex risk environments with strong international competition. Hedging gas can help deal with these pressures over the near term, but is less feasible over the long run.

The variety of approaches to hedging across all these sectors, and across different players within the same sector of the industry, nicely demonstrates a couple of the key principles of risk management: that hedging programs do not alter expected revenues or costs over the long-term and that they should not be undertaken simply for the sake of reducing commodity risk. If that was the case, since all of these players are facing basically similar problems regarding gas price volatility, they all would (should) have chosen to hedge similarly – but they did not. The reason is because they are all correctly choosing to hedge (or not) because of how gas-price risk creates other problems for their operations. Depending on their size, financial strength, diversity of products and markets, types of competitors, ability to pass on costs, regulatory oversight, demand predictability, horizon of investing and contracting, and ability to make non-financial adjustments to operations as gas prices rise or fall, they may have little or no use for hedging, or a very strong need.

While electric and gas utilities are making far greater use of hedging tools relative to the 1990s, the hedging programs implemented by many of them could almost certainly benefit from some enhancements. First, many gas LDC policies are really just risk-reduction, not risk-management programs. That is, their policies are mostly procurement rules and strategies designed to substitute some forward and collared positions for what would otherwise be short-term indexed positions, with parameters for the type and timing of hedges based largely on similarity of procurement approaches across the industry. This certainly succeeds in reducing risk, but it is a fairly static approach that invites criticism if/when risk circumstances change while procurement practices do not. If gas utilities were to rely more on simulating and controlling likely future gas cost variability, they could identify shifts in circumstances that justify alternative hedging tactics, thereby reducing their regulatory exposure to cost disallowances.

On the electric side, many electric companies keep track of gas risk separately from other fuel and power supply risks, especially purchased (and sold) power transactions. While it is useful to manage each separately, they are closely related, since gas generation and wholesale power transactions tend to substitute for each other in short to mid-term operations, and they often account for a large part of utility fuel and electricity supply expense. Combining these would increase the effectiveness of their hedging, though it is admittedly a complex analytic task.

Evaluating the market for the stability of risk factors is difficult but very important to all players in the gas industry. Key assumptions in risk management include the size and shapes of the prospective distributions of spot and forward price movements, correlations, and rates of mean reversion. If structural conditions are shifting, hedges that worked perfectly well in the past may become suddenly and perhaps embarrassingly or catastrophically ineffective. In general, gas producers appear to be more active than gas or electric utilities in monitoring shifts in market conditions, and they tend to make correspondingly much more significant adjustments to their hedge plans. While we are not advocating for utilities to implement the same dynamic programs that producers use, we do believe that utilities should also be closely monitoring market conditions, forward gas price volatility quotes, the relation of gas prices to drilling activity, oil prices, and the like, and engaging their regulators to discuss when changes to their hedge programs in the face of shifting market conditions may make sense for customers. At the very least, this will help clarify what risks a utility cannot control and cannot substantially hedge away.

Clarity and agreement about what is feasible to accomplish with risk management are important to all sectors of the industry, and reaching this understanding is sometimes neglected. In particular, it is important that corporate executives have reasonable expectations regarding the feasible performance of their hedging groups, whether for a regulated public or a privately held commercial operation. Unreasonable beliefs that risk management will be a source of profits have gotten more than a few organizations or managers into trouble. Of course, risk management can help increase profits, but not from the hedges themselves. (If risk management is expected to produce profits, then it is really a financial trading operation that should be allowed to speculate on its expertise, not asked to stay within the confines of the company's physical gas consumption or production.) Profits will increase to the extent that hedging reduces corporate exposure to other problems that would constrain the firm. Executives therefore must be involved in specifying what those critical exposures are and how close he or she is willing to get to their edges, so that risk managers know what is being sought. Many organizations treat risk management goals as a tactical aspect of operations, rather than as a strategic, executive level question.

It is not clear how much of a problem, if any, is created by the relatively short time horizon of liquidity in available hedging instruments. Even with better long term liquidity, companies that want to hedge substantially into the future would still face large credit risks and/or collateral requirements that may make longer-term hedging unattractive. Non-financial solutions, such as building more operational flexibility into production processes, may be a better long-run solution to uncertainty, since often the question is not just what gas prices will be, but also what other environmental rules and regulations will apply, what new technologies will be in place, and what your customer's demand for your products or energy services will be. Simply having better gas hedges would not address most of these problems.

Managing gas price volatility is likely to be an on-going issue for U.S. gas market participants. In some ways, it appears we are in a period of relative calm, but because there are considerable uncertainties facing U.S. gas markets right now, great caution should be taken before concluding that exposure to high gas prices and volatility that was experienced in the past ten years has come to an end. U.S. gas markets today continue to reflect weak gas demand (especially in the industrial sector) as a result of the economic crisis. They also reflect over-supply conditions due to shale drilling that is at least partially driven by lease requirements (rather than direct economic considerations). Low prices tend to slow down well development, so a future economic upturn could result in a renewal of higher prices and increasing volatility. Some pending public policies, especially air quality restrictions, may lead to substantial new demand for natural gas in the electric power sector as a result of the possible retirement of older, smaller coal-fired power plants that do not have adequate pollution controls.

Climate policies may have both positive and negative impacts on U.S. gas demand over time. Gas is seen by many as one of the quickest and most cost-effective means by which the U.S. could achieve meaningful reductions in greenhouse gas emissions. Since natural gas emits about 40% less CO<sub>2</sub> than coal, using natural gas to displace coal-fired generation could reduce CO<sub>2</sub> at a fairly low cost – a few tens of dollars per ton – and doing so would also reduce other criteria pollutants. However, we do not have strong political momentum for climate policy legislation, instead seeing more local and piecemeal policies such as state renewable energy mandates. These also reduce carbon, but often at a fairly high price per kWh of energy and per ton of CO<sub>2</sub> avoided. In fact, their growing use may reduce natural gas demand in the coming years (where they displace gas-fired generation on the margin in some regions). On the other hand, CO<sub>2</sub> pricing under a cap and trade regime could lead to increased gas demand in the power sector from coal to gas dispatch switching. Compressed Natural Gas (CNG) vehicles might also gain a boost in the coming years and also contribute to increased gas demand. In the much longer run, e.g. around 2030-2050, traditional gas-fired generation may become obsolete. Our electric fleet will have to be virtually carbon-emissions free if we are to achieve anything approaching the deep CO<sub>2</sub> reductions called for in recent global warming draft legislation or scientific recommendations, so gas plants will need to have carbon capture or be replaced with something else.



All of this suggests the demand for gas will continue to ebb and flow, perhaps fairly dramatically, with major regulatory and technological changes that have yet to be sorted out. If so, gas market participants should be vigilant in assessing changing gas market conditions, and not assume that gas price volatility will be lower than that experienced over the past decade given the uncertainties now facing U.S. gas markets.