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QUANTIFYING THE VALUE THAT WIND POWER PROVIDES AS A HEDGE AGAINST VOLATILE NATURAL GAS PRICES

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Abstract

Advocates of renewable energy have long argued that wind power and other renewable technologies can mitigate fuel price risk within a resource portfolio. Such arguments – made with renewed vigor in the wake of unprecedented natural gas price volatility during the winter of 2000/2001 – have mostly been qualitative in nature, however, with few attempts to actually quantify the price stability benefit that wind and other renewables provide. This paper attempts to quantify this benefit by equating it with the cost of achieving price stability through other means, particularly gas-based financial derivatives (futures and swaps). We find that over the past two years, natural gas consumers have had to pay a premium of roughly 0.50¢/kWh over expected spot prices to lock in natural gas prices for the next 10 years. This incremental cost is potentially large enough to tip the scales away from new investments in natural gas-fired generation and in favor of investments in wind power and other renewable technologies.

Introduction

For better or worse, natural gas has become the fuel of choice for new power plants being built across the United States. The electricity crisis that hit California and other states in 2000/2001, however, highlights (among other things) the risk of relying too heavily on a single fuel source: the sharp increase in natural gas prices in the winter of 2000/2001 contributed to the bankruptcy of California's largest utility and a growing state budget deficit, while the commensurate price decrease over the remainder of 2001 left the state holding over-priced power contracts.

Against this backdrop, renewable energy resources such as wind power, which by their nature are immune to natural gas fuel price risk,[1] provide a real economic benefit: unlike natural gas-fired generation,[2] renewable energy is typically sold under fixed-price contracts. Building upon earlier analysis

[1] While this paper focuses only on fuel price risk, we acknowledge that the use of renewable energy and natural gas-fired generation involve many different types of risks, including performance risk (e.g., derived from intermittent renewable generation), environmental risk (e.g., a carbon tax adversely affecting gas-fired generation but benefiting renewables), and demand risk (e.g., the risk that power from a new plant will not be needed, which can be mitigated by the modularity and short construction lead times of renewables). While markets are beginning to value some of these risks (e.g., some wind plants have auctioned off emissions reduction credits; some utilities impose a ¢/kWh adder to the cost of wind power to account for the cost of firming intermittent resources), to date the fuel price risk mitigation benefits inherent in renewable energy technologies have, with a few exceptions (Awerbuch 1993, 1994; Brower 1997; Hoff 1997; Kahn and Stoft 1993), been recognized only in a qualitative sense. We further acknowledge that, while we focus solely on gas price volatility, there are many additional causes of volatility in wholesale electricity markets, some of which may not be hedge-able. Finally, our analysis does not consider the potentially large macroeconomic benefit to society if the use of renewable energy even marginally reduces natural gas prices as a result of reduced demand.

[2] Natural gas-fired generators can sell their output either (1) at fixed prices, (2) through contracts that are indexed to the price of the fuel input, or (3) through tolling arrangements. The aim of this paper is to evaluate the incremental

of this issue (Awerbuch 1993, 1994; Brower 1997; Hoff 1997; Kahn and Stoft 1993), this paper aims to quantify the hedge value of renewable energy by equating it with the cost of eliminating natural gas price risk through alternative means – specifically, through hedging with gas-based financial derivatives. Our hope is that policymakers and regulators will use this information to establish practical mechanisms that enable renewable technologies to capture the full value of the price stability benefit they provide.

A fundamental assumption underlying our analysis is that utilities and ratepayers value price stability.[3] Given this assumption, a utility looking to expand its resource portfolio should compare the cost of renewable technologies to the *hedged* or *guaranteed* cost of new natural gas-fired generation, rather than to *projected* costs based on *uncertain* gas price forecasts. To do otherwise would be to compare apples to oranges: by their nature, renewable resources such as wind power carry no natural gas fuel price risk, and if the market values that attribute, then the only appropriate comparison is to the *hedged* cost of natural gas-fired generation. We fear, however, that investments in renewable energy are often compared to the cost of index-based gas-fired generation using long-term forecasts of future spot gas prices that do not incorporate the cost of hedging.

Our analysis proceeds as follows. We begin by briefly exploring various ways to hedge natural gas price risk; our objectives in doing so are to quantify any *explicit* premiums involved and to determine which instruments create a hedged exposure similar to that provided by renewables. Next, we examine market prices of long-term natural gas swaps in search of any embedded or *implicit* premiums, which we equate to the cost of hedging natural gas price risk through "traditional" means. A subsequent discussion of the Capital Asset Pricing Model (CAPM) provides theoretical support for the existence of a risk premium, and we apply CAPM to natural gas prices in an attempt to reconcile economic theory with our empirical findings. Finally, we conclude by drawing together our findings and discussing how to interpret them.

Financial and Physical Hedging Instruments and Their Explicit Costs

A utility wishing to hedge its exposure to natural gas price volatility can either invest in renewable energy, or instead choose among a number of gas-based financial and physical hedging instruments.[4] Financial hedges include futures (or, more generically, forwards), swaps, options on futures, or some combination or derivation thereof (e.g., collars). Physical hedges include long-term fixed-price gas supply contracts and natural gas storage.

Lacking sufficient space to go into the amount of depth warranted for this section, we nevertheless briefly describe each of these gas-based instruments, the specific exposures they hedge, and their explicit costs from the perspective of a gas-fired generator or electric utility exposed to gas price volatility. Our overriding objective in this section is to determine which of these instruments creates a hedged exposure that is most consistent with the benefits provided by renewable energy, and can therefore serve as an appropriate basis from which to determine the cost of hedging that renewables avoid. This cost can then

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cost to the natural gas generator of offering a fixed-price contract or, alternatively, the cost to the electricity purchaser of hedging its natural gas price risk exposure under an indexed or tolling contract.

[3] The degree of price stability desired will depend on many factors, including individual risk preferences and the cost of achieving such stability. Our analysis makes no contributions in this area. Instead, our goal is simply to determine the cost of hedging with natural gas swaps on a ¢/kWh basis. Armed with this knowledge, the reader (or gas consumer) must decide – for whatever level of price stability is desired – whether to hedge using financial swaps and futures (and pay the associated hedging costs), or seek the same level of stability using renewables.

[4] Investments in energy efficiency (e.g., through demand-side management) could also reduce exposure to volatile gas prices. Though not explicitly targeted as such, much of the discussion in this paper is also applicable to energy efficiency.

be used when comparing renewable energy with variable-priced natural gas-fired generation, either as an adder to the cost of gas-fired generation, or as a credit to the cost of renewables.

Readers well-versed in hedging or otherwise not interested in wading through this material may skip directly to the brief summary at the end of this section.

Futures

Natural gas futures, which are actively traded on the New York Mercantile Exchange (NYMEX), enable buyers and sellers to lock in a known price in any or all months up to 72 months (6 years) in the future. Each natural gas futures contract is for 10,000 mmBtu to be delivered at the Henry Hub in Louisiana at as uniform an hourly and daily rate of flow over the course of the delivery month as is possible.[5]

Figure 1 depicts the NYMEX natural gas futures "strip" as it closed on November 6, 2001.[6] On that day, the owner of a natural gas turbine (or an electric utility) exposed to gas price volatility could have purchased the appropriate number of futures contracts for delivery in each of the 36 months in the strip and thereby locked in the variable-but-known 3-year price stream (excluding the cost of pipeline transport) depicted in Figure 1. Note that while this transaction removes the risk of paying higher gas prices over the next 3 years, it also forfeits the potential to benefit from paying lower gas prices should they transpire over this period. Because the hedger pays no explicit up-front premium, but rather merely purchases gas in advance, hedging with futures is often considered to be "costless." We challenge this notion in a later section of this paper.

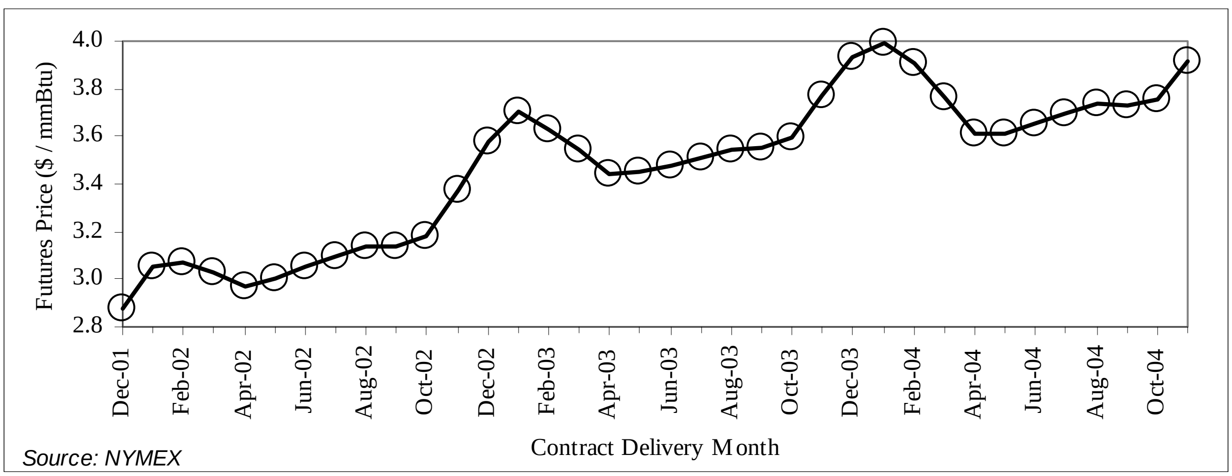

FIGURE 1. NATURAL GAS FUTURES STRIP ON 11/06/01

[5] Because gas delivered to the Henry Hub does not, without transportation, satisfy the physical needs of end-users located in other parts of the country, the NYMEX futures market typically does not provide a perfect hedge. Locational basis risk – i.e., the price differential between gas at the Henry Hub and the point of end-use – remains, and can also be hedged if desired.

[6] Note that Figure 1 only goes out 36 months; the NYMEX extended the strip out 72 months starting in December 2001 (partially an opportunistic response to the collapse of Enron, which had historically dominated the longer-term "over-the-counter" market), but to match data presented later in this paper, we are interested in prices from mid-November 2001.

Swaps

Natural gas swaps enable two parties to exchange, or "swap," floating spot market prices for fixed gas prices over a predefined term, thereby allowing natural gas consumers to lock in a fixed price over the duration of the swap agreement. For example, an unhedged generator facing a variable-priced gas supply (e.g., Henry Hub spot prices) can eliminate price risk by entering into a swap with an over-the-counter market maker, whereby the market maker agrees to pay the generator's variable price liability (i.e., the Henry Hub spot price) in exchange for being paid a fixed price for the duration of the swap term. In perhaps the most common case, where the floating price is indexed to the Henry Hub spot price, the fixed price stream will be essentially equivalent to the levelized price of the NYMEX futures strip (remember that NYMEX futures are deliverable to Henry Hub) over the appropriate term.

To apply real numbers to this concept, on November 6, 2001, Enron – the dominant market maker in natural gas swaps prior to its bankruptcy in late 2001 – was offering (indicatively) a 2-year natural gas swap indexed to Henry Hub at a price of $3.317/mmBtu. Thus, a buyer of that swap would pay Enron $3.317/mmBtu for the next two years, while Enron would pay the buyer the Henry Hub spot price (which the buyer could then use to purchase physical gas on the spot market at an effective price of $3.317/mmBtu). As one would expect, levelizing the 24-month NYMEX futures strip from Figure 1 (at a discount rate of 5%) yields a price of $3.318/mmBtu – essentially the same as Enron's swap price.[7]

Because swaps can be thought of as the levelized equivalent of the futures strip (or more generally, the forward strip), they too are often considered to be "costless" for the same reason as futures are: there is no explicit up-front cost or premium. Again, we shall challenge this notion later.

Options on Futures

When hedging with futures or swaps, a gas-fired generator (or electric utility) locks-in a natural gas price in advance, thereby eliminating its exposure to both rising *and* falling gas prices. If, instead, a gas-fired generator (or utility) wants to remove the risk of rising gas prices without relinquishing the ability to capitalize on falling prices, the generator can purchase a "call" option on a natural gas future that gives him the right – but not the obligation – to buy the futures contract at a pre-determined price (the "strike price").[8] In exchange for this "insurance" against only unfavorable price movements, the purchaser of an option pays an explicit up-front premium that varies according to the level of the strike price relative to the underlying futures price, the amount of time before the option expires, and the volatility of the underlying futures contract.

Figure 2 depicts premiums on "at-the-money" (i.e., the strike price equals the underlying futures price) call options on the 12-month futures strip as priced on November 6, 2001. Since all 12 options are at-the-money, the premium paid to acquire these options (represented by the vertical bars) reflects only the time to expiration – note the steady increase in premiums as one goes further out in time – as well as the volatility of the underlying futures contract. The dotted horizontal line represents the average options premium that one would have to pay to hedge with options over the entire year – almost $0.5/mmBtu. In return for this rather hefty premium, the hedger is not only protected against price increases, but will also benefit from price decreases.

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[7] Because levelizing involves taking the present value of a price stream and amortizing it forward at the same discount rate, the calculation is relatively insensitive to the level of the discount rate chosen.

[8] The NYMEX lists options on natural gas futures out 12 consecutive months, and then every 3 months thereafter up to 72 months (or until liquidity fizzles out).

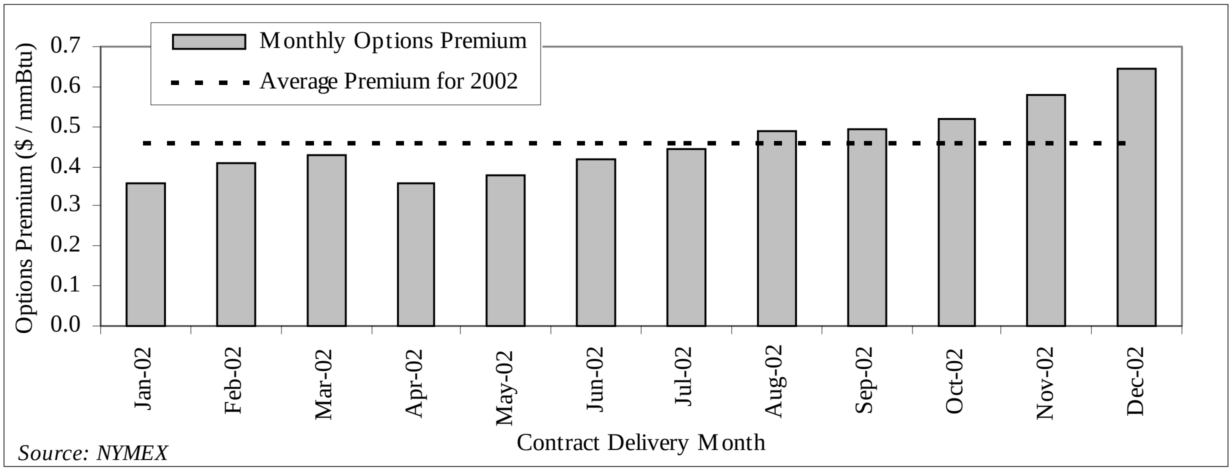


FIGURE 2. NATURAL GAS AT-THE-MONEY OPTIONS STRIP ON 11/06/01

Physical Gas-Based Hedges

While financial hedges are becoming increasingly common, physical hedges have historically been the mainstay of gas price risk management. Physical hedges include fixed-price natural gas supply contracts and natural gas storage facilities. Since, in contrast to many financial hedges, physical supply contracts are typically backed by physical assets and actual production, longer term contracts – on the order of 10 to 20 years – are perhaps more common than with financial hedges, which seldom exceed 10 years.

Aside from this potentially relevant difference,[9] however, financial and physical hedges should – at least theoretically – be priced almost identically. If they are not, an arbitrage opportunity exists. For example, if a 10-year fixed-price physical supply contract is priced substantially below a 10-year financial gas swap, then one could simultaneously buy the physical supply and sell the swap, thereby locking in a "riskless" profit margin.[10] Because of the market discipline imposed by arbitrage and the difficulty in obtaining details on actual long-term contracts for physical supply, for the purposes of this paper we simply assume that long-term physical supply contracts are economically identical to swaps or futures/forwards of the same duration.

Physical storage facilities enable gas to be injected when prices are low and withdrawn when prices are high, thereby providing a form of hedge. In testimony before the Colorado PUC's investigation into gas pricing by regulated natural gas utilities, Xcel Energy noted that the cost of seasonal storage varies by field, but has generally been in the $0.70 to $1.00/mmBtu range (Stoffel 2001). Note that this cost is close to the explicit cost of hedging with options – this is perhaps not that surprising, given that one could think of storage as providing the holder with an option to either pay current market prices or else withdraw gas from storage. In other words, storage provides a physical option.

[9] This difference is relevant given the expected lifespan of 20 years or longer for renewable energy technologies. It may simply be impossible or impractical to use financial instruments to hedge gas price risk for such a long duration.
[10] This arbitrage would not be entirely riskless because credit risk (i.e., risk of default) would undoubtedly remain.

Summary of Hedging Instruments

Of the various forms of hedging discussed above, only options have explicit up-front and easily quantifiable premiums. As demonstrated, these premiums can be rather expensive – data from November 6, 2001 indicate that hedging natural gas price risk for just a single year (2002) using at-the-money call options would cost almost \$0.50/mmBtu, or 0.35¢/kWh assuming an aggressive heat rate of 7,000 Btu/kWh. This premium would increase if one attempted to extend the option hedge farther out into the future. The cost of physical storage – which can be thought of as a physical option – is similar, on the order of \$0.70 to \$1.00/mmBtu.

While provocative, options premiums unfortunately tell us little about the hedge value of renewable energy,[11] because an options hedge results in an exposure that is different from that provided by renewables. Call options protect the buyer against gas price increases and preserve the ability to profit from gas price reductions, while renewables also protect the buyer against gas price increases *but forfeit* the ability to profit from gas price reductions. Thus, in order to gauge the hedge value of renewables, we must instead look to futures and swaps, which provide a hedged exposure similar to that of renewables – i.e., immune to both price increases and decreases. This realization increases the complexity of our task, since, as noted above, both futures and swaps are often considered to be "costless" hedges. We now address this issue by searching for the true (implicit) cost of hedging gas price risk using futures and swaps.

The Implicit Cost of Hedging Price Risk with Futures and Swaps

At the time a hedge is established, the cost of hedging can be thought of as being equal to any premium paid to lock in prices going forward, plus any transactions costs incurred.[12] This section first provides empirical evidence of an implicit premium embedded in swap prices, and then turns to economic theory for justification of such a premium. Since we look only at offered prices (instead of bids or mid-market prices), transaction costs inherent in the bid/offer spread are automatically embedded in any implicit premium.

Empirical Evidence of a Premium

The previous section presented the argument that hedging with futures and options is "costless," based on the fact that futures and swaps do not require payment of an explicit up-front premium. This argument fails to consider, however, whether any *implicit* premiums are embedded in the futures (or swap) price itself. Perhaps the only way to identify the existence of any embedded premiums is to compare futures (or swap) prices to market expectations of future spot prices: if hedging with futures truly is "costless," then the futures (or swap) price should exactly equal market expectations of future spot prices.

To examine this possibility, we collected swap price data (from EnronOnline) and long-term natural gas price forecasts (from the Energy Information Administration, or EIA). Table 1 presents the Enron swap

[11] Though at least one study has attempted – in our view erroneously – to make this link. See Brathwaite and Gopal (1992).

[12] Of course, as the future unfolds, there may also be a potentially large *opportunity cost* of hedging if, for example, spot gas prices decline but the hedged generator is unable to capitalize on this price movement due to being hedged. Since this opportunity cost applies equally to all non-option hedges – futures, swaps, physical gas supply, and renewables – and our purpose in this paper is to draw distinctions between the first three and renewables, it is not useful to dwell on this point. The question of opportunity cost essentially boils down to one of *whether or not* and *how much* to hedge – questions we are not asking.

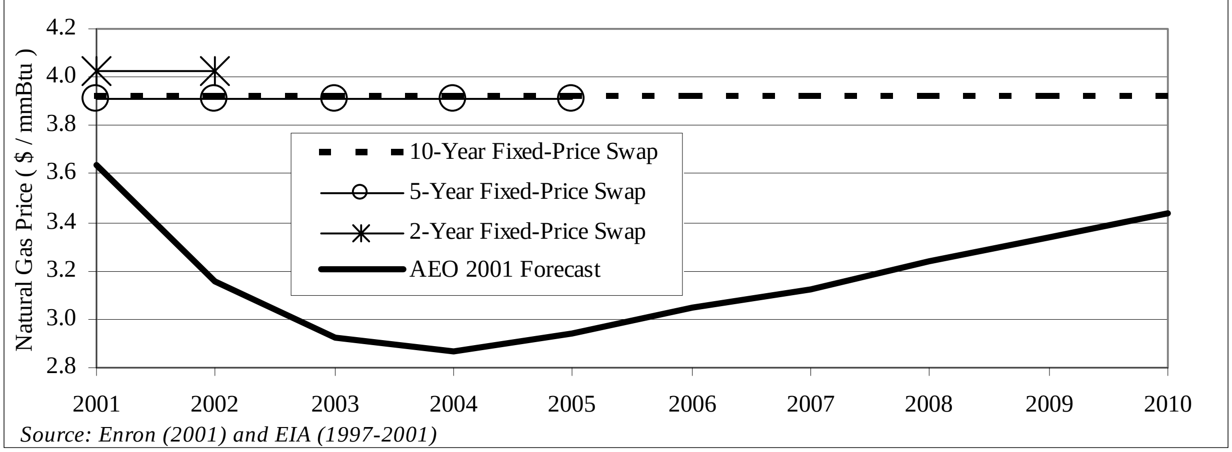
price data and shows that on November 6, 2001, for example, a gas-fired generator or electric utility could have locked in a fixed gas price of $3.876/mmBtu for the next 10 years. Note that for each swap term, we have only four data points – November 6 and 13 from both 2000 and 2001.[13] Although our sample size is troublingly small, it is at least diverse: November 2000 and November 2001 represent very different market environments of precipitously rising prices (witness the 2-year swap price above the 5- and 10-year price) and relative calm, respectively. Interestingly, the 10-year swap price is not very different in 2000 and 2001 – perhaps an indication that short-term price spikes do not significantly impact the long end of the forward curve in the absence of changes in long-term fundamentals.

TABLE 1. ENRON FIXED-PRICE SWAP DATA (INDICATIVE OFFERS, $/MMBTU)

	2001		2000	
Swap Term	**November 6**	**November 13**	**November 6**	**November 13**
2-Year	3.317	3.288	4.010	4.040
5-Year	3.600	3.650	3.905	3.910
10-Year	3.876	3.946	3.928	3.920

Source: Enron (2001)

As a proxy for market expectations of future spot prices, we used the EIA's reference case forecast of natural gas prices delivered to electricity generators, which is generated in the Fall of each year and presented in their *Annual Energy Outlook* (AEO) series released in November. To make a direct comparison to the Enron swap prices, which are indexed to the Henry Hub, we would ideally want to use a forecast of Henry Hub spot prices, which the EIA does not provide. Instead, we estimated the average cost of transportation from Henry Hub to electricity generators nationwide by comparing historic Henry Hub spot prices to delivered (to electricity generators) spot prices on a monthly basis over the past four years. This comparison revealed an average transportation margin of $0.33/mmBtu, with a 95% confidence interval that ranges from $0.22 to $0.43/mmBtu. To account for this transportation margin, we subtracted $0.33/mmBtu from the EIA forecast of prices delivered to electricity generators. Figures 3 and 4 show the resulting forecast from the end of 2000 and 2001, respectively, plotted against the corresponding Enron swap prices from each year (since we have no reason to pick one day over the other, we averaged swap prices from November 6 and November 13 of each year).



Source: Enron (2001) and EIA (1997-2001)

FIGURE 3. NOVEMBER 2000 SWAP PRICES VS. AEO 2001 NATURAL GAS FORECAST

[13] Unfortunately, Enron slipped into bankruptcy soon after we began collecting this data, greatly hindering our efforts to obtain a larger sample size.

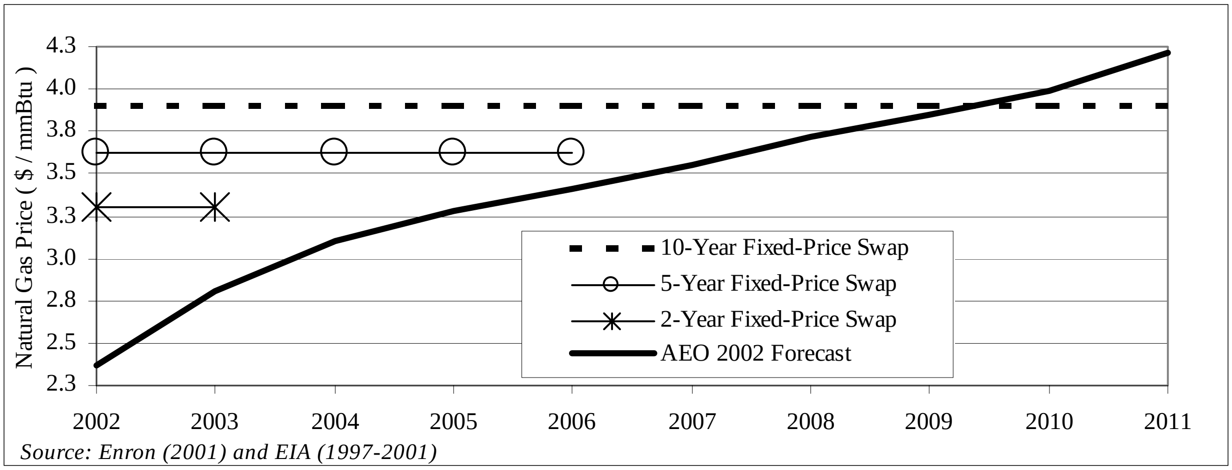


FIGURE 4. NOVEMBER 2001 SWAP PRICES VS. AEO 2002 NATURAL GAS FORECAST

Figures 3 and 4 show that in both 2000 and 2001, the EIA forecast is well below the swap prices for most or all of the 10-year period. This finding suggests that gas consumers must pay an implicit premium to lock in gas prices through a swap. Table 2 presents these average premiums.[14] Because investments in renewable energy are typically long-term, the 10-year average premiums of $0.56/mmBtu and $0.76/mmBtu in 2001 and 2000, respectively, are of most interest to our analysis. Translated into ¢/kWh using an aggressive heat rate of 7,000 Btu/kWh, the 10-year premiums equate to 0.39¢/kWh and 0.53¢/kWh that one must pay to hedge natural gas price risk. If renewable energy technologies can provide this benefit at a lower cost, then utilities should – all else being equal – invest in renewables instead of new gas-fired generation.

TABLE 2. IMPLIED PREMIUMS (ENRON SWAP OFFERS – EIA GAS FORECASTS)

Swap Term	2001	2000
2-Year	$0.72/mmBtu (0.50¢/kWh)	$0.62/mmBtu (0.44¢/kWh)
5-Year	$0.66/mmBtu (0.46¢/kWh)	$0.79/mmBtu (0.55¢/kWh)
10-Year	$0.56/mmBtu (0.39¢/kWh)	$0.76/mmBtu (0.53¢/kWh)

Note: Conversion from $/mmBtu to ¢/kWh assumes a heat rate of 7,000 Btu/kWh

Obviously, confidence in these results hinges upon several assumptions, including: (a) that the EIA forecasts were generated at roughly the same time that the swaps were priced (i.e., the EIA and the market were privy to the same information); (b) that the EIA forecasts accurately represent the market forecast; and (c) that Enron pricing accurately represents market pricing. Below we address the reasonableness of each of these assumptions in turn.

Coincidence of Gas Forecast with Swap Pricing. The Enron swaps were priced in the first two weeks of November 2000 and 2001. The AEO-2001 gas price forecast was generated between early-September and mid-October 2000, while the AEO-2002 forecast was generated during the first three weeks of October 2001. An examination of the December 2000 and 2001 futures contracts (i.e., the "prompt-month" or "first-nearby" contracts) reveals that futures prices were essentially unchanged from the time the forecasts were generated to the time the swaps were priced. Assuming that any fundamental change

[14] We derived the premiums by levelizing the EIA forecasts (using a discount rate of 5%) and subtracting them from the averaged swap prices.

in the market over this time period would have been reflected in prompt-month futures prices, and seeing no evidence of such a change, we conclude that timing is not an issue, and the forecasts and swap price data can be considered coincident.

Representativeness of EIA Forecast. Each year in the AEO, the EIA compares its natural gas forecast to a number of different private sector forecasts for certain years (e.g., 2015 and 2020). While the private sector forecasts are typically generated much earlier in the year than the EIA forecast and are therefore perhaps not strictly comparable, an examination of forecast comparisons from the last 5 years of AEO publications reveals that the EIA forecast has consistently been at the upper end of the forecast range. At least for the AEO 2002 forecast, this is particularly surprising, given that most of the private sector forecasts were generated in the first quarter of 2001 – when spot prices were at all-time highs – while the EIA forecast was generated in late October 2001, by which time spot prices had settled back to around \$2.50/mmBtu. These findings suggest that we need not worry that the EIA forecast is *under-representing* the "market" forecast (and thereby over-inflating our empirically derived risk premiums).

Representativeness of Enron Swap Pricing. The story of Enron's demise is by now well known. A relevant concern is whether or not Enron swap prices from November 2001 are representative of market prices, or perhaps reflect an increased credit risk premium, given the events that were unfolding at that time. Two responses are in order. First, as mentioned earlier, Enron's 2-year swap prices from November 2001 match up almost perfectly with the levelized 2-year NYMEX futures strip, implying that – at least on the short end of the curve – Enron's prices did not reflect substantial credit risk at that time. Second, while the fraudulent activities that eventually led to Enron's downfall may have been taking place in November 2000 (i.e., a year earlier), the market certainly had no idea at that time that Enron posed any serious credit risk, so swap prices from November 2000 – which show an *even larger* risk premium – should not be tainted by credit concerns.

In summary, our analysis finds each of these three critical assumptions to be reasonable, allowing us to conclude that our findings of substantial premiums in the long-term natural gas swap market do not appear to be merely a product of data problems, but rather represent a real and significant phenomenon.

Theoretical Support for the Existence of a Risk Premium

How can one explain the existence of implicit premiums as high as \$0.76/mmBtu (i.e., 24% above the EIA forecast), as found in the previous section? One potential explanation is that this premium simply reflects the high degree of price volatility in the natural gas market and the amount that gas consumers are willing to pay to eliminate that volatility. Though intuitively plausible, this argument, at least in its most general form, fails to consider that natural gas producers also face price volatility as sellers, and may be equally willing to forsake potential revenue (i.e., price their product at a discount) to lock in prices (and their revenue stream) over the long term. With both consumers and producers theoretically seeking price stability, it becomes difficult to draw any conclusions about resulting price levels or premiums.

But what if price volatility was not equally damaging to the producer and consumer? What if producers benefited from volatility, while consumers were hurt by it? In this case, producers would require compensation (i.e., a premium) for being locked into long-term fixed-price contracts, and consumers would be willing to pay such compensation. Economic theory provides some support for this very scenario in the form of the Capital Asset Pricing Model (CAPM).[15]

While CAPM was originally derived as a financial tool to be applied to investment portfolios, its basic

[15] For a good introduction to CAPM, see Brealey and Myers (1991).

tenet – that an asset's risk depends on the correlation of its revenue stream with variability in the asset-holder's overall wealth – can be applied much more broadly, for example in evaluating investments in physical assets such as power plants (Awerbuch 1993, 1994; Kahn & Stoft 1993). Specifically, in the context of natural gas-fired generation, one can think about the correlation between a gas consumer's overall wealth (as proxied by the economy or, more specifically, the stock market) and natural gas prices. If gas prices, and therefore consumer expenditures on gas, rise as the stock market declines (e.g., because rising gas prices hurt the economy), then natural gas is said to have a negative "beta,"[16] and is risky to gas consumers and beneficial to gas producers. In other words, at the same time as gas consumers and producers feel the pinch of a weak stock market, expenditures on natural gas also rise, compounding overall wealth depletion among consumers while providing some consolation to producers.

In this specific case, where gas with a negative beta is risky to consumers and beneficial to producers, consumers have an incentive to hedge natural gas price risk, while producers do not. Intuitively, it follows that if both consumers and producers shared identical expectations of future spot gas prices, then producers would require – and consumers would be willing to pay – a premium over expected spot prices in order to lock in those prices today. Using slightly different approaches, both Pindyck (2001) and Hull (1999) mathematically demonstrate this to be the case: when beta is negative, futures prices should, at least theoretically, trade at a premium to expected spot prices.

Thus, if the beta of natural gas is indeed negative, this theory might explain our empirical observations of an implicit "risk" premium embedded in swap prices (as presented in Table 2). One can test this notion by regressing natural gas price changes against stock market returns. Below we survey past efforts to quantify the beta of natural gas, report results from our own analysis, and then reconcile our regression results with our empirical observations of risk premiums in the long-term natural gas market.

Past Estimates of Beta. Literature from the early 1990s supports the existence of a negative beta for natural gas. Kahn and Stoft (1993) regressed spot wellhead gas prices against the S&P 500 using annual data from 1980 through the first 6 months of 1992 and arrived at an estimate of beta = -0.78 (±0.27 standard error). Awerbuch has written several papers advocating the use of risk-adjusted discount rates for evaluating investments in generation assets; in them he usually cites a natural gas beta ranging from -1.25 to -0.5 (Awerbuch 1993, 1994). Awerbuch (1994) also cites another study from 1993 (by Talbot) as having found a natural gas beta of -0.45.

More recent literature suggests that the beta of natural gas may not be negative. Pindyck (2001) cites estimates of betas for crude oil in the range of +0.5 to +1.0, and qualitatively explains why one should expect to see positive betas – strong economic growth leads to higher prices for industrial commodities. Although Pindyck does not explicitly look at natural gas, since natural gas and crude oil prices are moderately correlated, one could infer that his assertion of a positive beta for oil might also apply to natural gas.

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[16] In its original application to the stock market, beta represents the risk premium of a particular stock, and is related in a linear fashion to that stock's market risk (i.e., beta = expected risk premium on stock / expected risk premium on entire market). Stocks that carry the same market risk as the entire stock market (i.e., stocks whose returns are perfectly correlated with those of the broad market) have a beta of 1, while stocks that are perfectly uncorrelated with the market have a beta of 0. Similarly, stocks that are riskier than the market as a whole have betas > 1, while stocks that are negatively correlated with the market have betas < 0. While *assets* with a negative beta are desirable for diversification purposes, *liabilities* with a negative beta are undesirable for the same reason. In the case of natural gas, the producer holds the asset (and benefits from a negative beta) while the consumer is faced with a liability (and is hurt by a negative beta).

Our Estimate of Beta. Figure 5 graphically displays our estimate of beta over time.[17] The dotted line represents a "cumulative" estimate of beta, resulting from progressively longer-term regressions as one moves forward in time.[18] The gray shaded area represents a 90% confidence interval around our central estimate of cumulative beta. Meanwhile, to illustrate shorter-term variations, the solid line represents a rolling 10-year estimate of beta.[19]

As shown, our cumulative estimate of beta (the dashed line) is fairly stable over time, ranging from -0.2 to -0.4 and coming to rest in 2001 at -0.26 – less than half as large as estimates from the early 1990s, yet still negative.[20] Even so, the 90% confidence interval, while skewed to the negative side of zero, is fairly wide and does not rule out the possibility of a positive beta, particularly from 1996 on. In fact, it is clear from both the confidence interval and the rolling 10-year estimate of beta that Awerbuch and others who looked at gas betas in the early 1990's were doing so at perhaps the optimal moment to conclude a negative beta. Since that time, the confidence interval has widened considerably – the opposite of what one would expect as sample size increases – and the rolling 10-year beta has flipped from negative to positive in 1996, where it remained until the natural gas price spike of 2000 sent it back below zero. Thus, while the cumulative beta shown in Figure 5 appears to, with at least some degree of confidence, be negative, it would be unwise to conclude that this will always be the case.

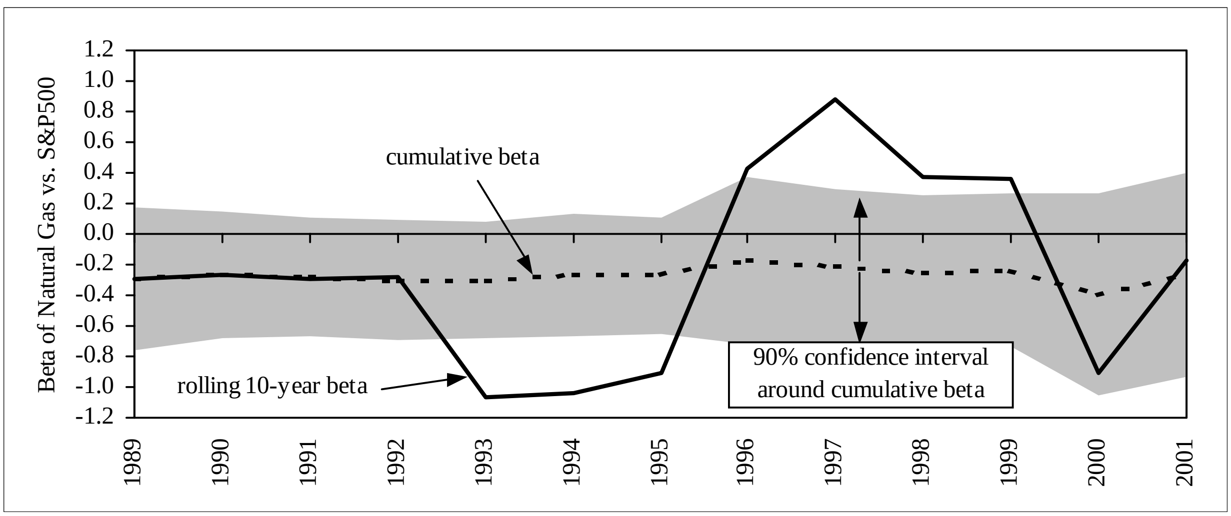

FIGURE 5. ESTIMATE OF BETA OF NATURAL GAS DELIVERED TO ELECTRICITY GENERATORS (AS REGRESSED AGAINST THE S&P 500)

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[17] We regressed EIA's historic natural gas prices delivered to electricity generators (which seemed more relevant for our purpose than wellhead prices) against the S&P 500 index. Like Kahn and Stoft (1993), we first attempted to use monthly data (going back to January 1979), but were unable to correct for seasonality despite employing several different approaches. As a result, we too retreated to using annual averages, which remove seasonality yet also mask intra-year movements and greatly restrict sample size. We corrected for autocorrelation using the Hildreth-Lu procedure.

[18] This is essentially a rolling regression with a fixed starting point; i.e., the first estimate of cumulative beta shown (in 1989) results from a 10-year regression, while the 1990 estimate is from an 11-year regression, the 1991 estimate is from a 12-year regression, and so on building up to a 22-year regression in 2001.

[19] This line is simply the result of a 10-year rolling regression; i.e., each year looks only at the past 10 years.

[20] Our cumulative estimate of beta through 1992 is less than half that estimated by Kahn and Stoft (1993) due to different data sources as well as our use of delivered prices instead of wellhead prices.

Reconciling Our Theoretical Estimate of Beta with Our Empirical Findings of Risk Premiums. Using the Enron swap price data and adjusted EIA gas forecasts, it is possible to back into an empirical estimate of the beta for natural gas. To do this, one must assume that the Enron swap price is "riskless" (i.e., known in advance and able to be locked in), while the price stream represented by the EIA gas forecast is "risky" (i.e., merely a forecast and bound to be wrong). One then calculates the present value of both price streams – the Enron swap price stream using the known "riskless" discount rate (i.e., the U.S. Treasury bill yield at the time), and the EIA forecast price stream using whatever discount rate results in the same present value as the discounted Enron swap price stream. The difference between the resulting empirically derived risk-adjusted discount rate and the known "riskless" discount rate is then divided by the "market risk premium" – i.e., the historic out-performance of risky assets (stocks) over riskless assets (T-bills) – to yield beta.

Performing this exercise using the 10-year swap prices and EIA forecasts presented in Figures 3 and 4, and data on the historic returns of stocks and T-bills going back to 1926 from Ibbotson (2001),[21] we arrive at an estimate of beta = -0.62 in November 2000 and beta = -0.35 in 2001. These empirical estimates are close to the regression estimates presented in Figure 5, which estimate beta = -0.40 through 2000 and beta = -0.26 through 2001. While this degree of similarity is reassuring, we should note that performing the same exercise with the 5-year and 2-year swap price data yields progressively higher estimates of beta – as high as –2.13 for the November 2001 2-year swap – which is somewhat less reassuring.[22]

Conclusions

Based on our analysis, we conclude that it costs approximately 0.5¢/kWh to hedge away natural gas price risk over a 10-year period using financial swaps. In particular, an empirical comparison of 10-year swap prices to levelized 10-year natural gas price forecasts reveals that swap prices traded at a premium of \$0.76/mmBtu (i.e., 24%) over the November 2000 forecast and \$0.56/mmBtu (i.e., 17%) over the November 2001 forecast, as presented in Table 2.[23] These premiums imply natural gas betas of -0.62 and -0.35, respectively – similar to the theoretical CAPM-derived betas of –0.40 and –0.26, thereby providing some level of comfort that our limited sample size is not overly biased. Converting these premiums to ¢/kWh terms at a heat rate of 7,000 Btu/kWh – a level of efficiency achievable only by state-of-the-art combined cycle gas turbines – yields 0.53¢/kWh and 0.39¢/kWh.

If consumers are risk averse and prefer stable over volatile prices, then the cost of hedging is one that natural gas generators – or similarly, those that purchase natural gas-fired generation – must bear. Conversely, and more to the point of this paper, 0.5¢/kWh can be considered the approximate hedge value that investments in renewable energy provide relative to variable-price, gas-based electricity contracts. Therefore, assuming that consumers value price stability and that regulators and utilities seek to compare various electricity generation sources on equal grounds when making resource decisions, this hedging cost should either be added to the cost of variable-price gas contracts or credited as a benefit to fixed-price renewable energy investments. To do otherwise would be to compare apples to oranges: by their nature, renewable energy resources such as wind power carry no natural gas fuel price risk, and if the market values that attribute, then the only appropriate comparison is to the *hedged* cost of natural gas-

[21] Ibottson (2001) calculates that the average compound annual return of T-bills and large stocks (similar to the S&P 500) from 1926 through 2000 is 3.8% and 11.0% respectively, which yields a "market risk premium" (i.e., the average annual return of stocks over bills) of 6.94% (i.e., (1+11.0%)/(1+3.8%)-1 = 6.94%).

[22] Perhaps over shorter terms (i.e., 2 years), the comparison to a long-term gas price forecast – which is by nature not very sensitive to changes in spot or short-term futures markets – is less valid.

[23] Since these premiums were generated from offer prices, they include the transaction costs inherent in the bid/offer spread.

fired generation. While half a cent per kWh is not an overly large number, it may in many cases be enough to tip the scales away from investments in new natural gas plants and in favor of investments in renewable energy, and in particular wind power, which has nearly achieved economic parity with natural gas-fired generation in several regions of the United States (e.g., Texas and the Pacific Northwest).

While we believe the analysis contained herein to be accurate given our limited data set, the quality of our analysis and results could be greatly improved with the addition of more extensive data. Much of the required information is not proprietary – Enron's indicative swap prices were publicly posted on EnronOnline.com – yet in our experience it has been difficult to obtain access to historic records of such prices (no doubt exacerbated by Enron's financial troubles). A more exhaustive survey of natural gas price forecasts may also provide a more accurate representation of the true "market forecast" of natural gas prices.

Future work, therefore, should focus on obtaining sufficient data of high enough quality to replicate our findings, hopefully with some consistency, both historically and going forward. Furthermore, as future work confirms the hedge value of renewable energy, industry experts, policymakers, and regulators should begin to explore practical mechanisms to incorporate that value into decision-making processes, thereby enabling renewable energy to capture the value of the price stability benefit it provides to the market.

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