LBNL-53587

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Accounting for Fuel Price Risk:
Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation

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August 2003

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The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-ACO3-76SF00098.

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Acknowledgements

Work reported here was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-ACO3-76SF00098. The support and encouragement of Susan Holte and Jack Cadogan of the U.S. Department of Energy is particularly acknowledged.

This report has benefited from the comments of Philip Budzik and Joseph Benneche (Energy Information Administration), James Read and Richard Goldberg (The Brattle Group), Brandon Owens (Platts Research & Consulting), and James Jensen (Jensen Associates). In addition, the following individuals commented on earlier incarnations of this work (prepared for the proceedings of *WINDPOWER 2002* and *ACEEE 2002 Summer Study on Energy Efficiency in Buildings)*: Shimon Awerbuch (SPRU, University of Sussex), Jack Cadogan (DOE), Devra Bachrach (NRDC), Frank Felder (Independent Consultant), Bob Grace (Sustainable Energy Advantage), Tom Hoff (Clean Power Research), Susan Holte (DOE), Mark Litterman (Portland General Electric), Amory Lovins (Rocky Mountain Institute), Elliot Mainzer (Bonneville Power Administration), Ross Miller (California Energy Commission), Kevin Porter (Exeter Associates, Inc.), Richard Price (Technology & Management Services, Inc.), and Osman Sezgen (Berkeley Lab). Finally, this work has also benefited from the comments of various conference attendees and seminar participants at *WINDPOWER 2002*, *ACEEE 2002 Summer Study on Energy Efficiency in Buildings*, *The University of California Energy Institute Seminar Series*, and the *NARUC 2003 Winter Committee Meetings*. Of course, any remaining omissions or inaccuracies are the authors' sole responsibility.

Executive Summary

Introduction

Against the backdrop of increasingly volatile natural gas prices, renewable energy resources, which by their nature are immune to natural gas fuel price risk, provide a real economic benefit. Unlike many contracts for natural gas-fired generation, renewable generation is typically sold under *fixed-price* contracts. Assuming that electricity consumers value long-term price stability, a utility or other retail electricity supplier that is looking to expand its resource portfolio (or a policymaker interested in evaluating different resource options) should therefore compare the cost of fixed-price renewable generation 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 carry no natural gas fuel price risk, and if the market values that attribute, then the most appropriate comparison is to the *hedged* cost of natural gas-fired generation.[1]

Nonetheless, utilities and others often compare the costs of renewable to gas-fired generation using as their fuel price input long-term gas price forecasts that are inherently uncertain, rather than long-term natural gas forward prices that can actually be locked in. This practice raises the critical question of how these two price streams compare. If they are similar, then one might conclude that forecast-based modeling and planning exercises are in fact approximating an apples-to-apples comparison, and no further consideration is necessary. If, however, natural gas forward prices systematically differ from price forecasts, then the use of such forecasts in planning and modeling exercises will yield results that are biased in favor of either renewable (if forwards < forecasts) or natural gas-fired generation (if forwards > forecasts).

In this report we compare the cost of hedging natural gas price risk through traditional gas-based hedging instruments (e.g., futures, swaps, and fixed-price physical supply contracts) to contemporaneous forecasts of spot natural gas prices, with the purpose of identifying any systematic differences between the two. Although our data set is quite limited, we find that over the past three years, forward gas prices for durations of 2-10 years have been considerably higher than most natural gas spot price forecasts, including the reference case forecasts developed by the Energy Information Administration (EIA).[2] This difference is striking, and implies that

[1] To the extent that it displaces gas-fired generation, development of new renewable generation may also *reduce* future gas prices to all sectors of the economy. Furthermore, long-term fixed-price renewable energy contracts may involve *less* credit risk than long-term fixed-price natural gas contracts (i.e., "conventional" hedges, such as gas forwards and swaps) of similar duration. Thus, separate from the "hedge value" of renewable energy discussed in this report, long-term fixed-price renewable energy contracts may provide incremental value over natural gas forward and swap contracts in the form of lower gas prices and reduced credit risk. These potential benefits – which are not included in our analysis – may become increasingly important over longer contract terms of 15-25 years.

[2] It deserves mention that reviewers of a draft of this report from the EIA have characterized their efforts as *projecting* natural gas *costs*, rather than *forecasting* natural gas *prices*. In other words, the EIA reference case assumes that weather and inventory patterns, as well as regulations – all of which can greatly impact market prices – remain "normal" (by historical standards) throughout the forecast period. In this sense, the EIA reference case "forecast" does not necessarily represent the *expected* or *most likely* future market price, and perhaps not even a market price at all. This subtle distinction is discussed in the full report; here we simply note that we use EIA

resource planning and modeling exercises based on these forecasts over the past three years have yielded results that are biased in favor of gas-fired generation (again, presuming that long-term price stability is desirable). As discussed later, these findings have important ramifications for resource planners, energy modelers, and policymakers.

Natural Gas Prices Are Highly Variable

For better or worse, natural gas has become the fuel of choice for new power plants being built across the United States. According to the EIA (2003), natural gas combined-cycle and combustion turbine power plants accounted for 96% (138 GW out of 144 GW total) of the total generating capacity added in the U.S. between 1999 and 2002. Looking ahead, gas-fired technology is expected to account for 80% of the 428 GW of new generating capacity projected to come on line through 2025, increasing the nationwide market share of gas-fired generation from 17% in 2001 to 29% in 2025 (EIA 2003).

With increasing competition for natural gas supplies, it is likely that gas prices will be as or more volatile than they have been in the past. Figure 1 shows first-nearby natural gas futures prices on a daily basis going back to the inception of trading on the New York Mercantile Exchange (NYMEX) in April 1990. While the “twin peaks” of December 2000 and February 2003 clearly dominate the graph and make the rest of the price history look comparatively tame, the reader should keep in mind that many of the “lesser” price spikes during the early 1990s represent doublings or more in price.

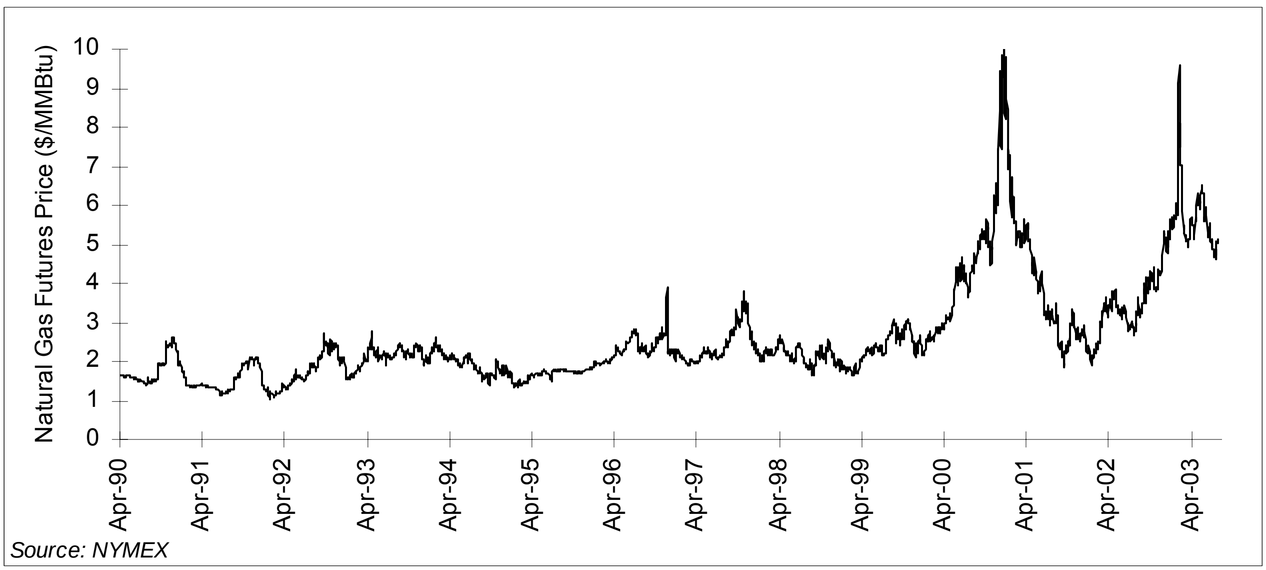

Figure ES-1. NYMEX Natural Gas Futures Prices (First-Nearby Contract)

As implied by Figure ES-1, not only have gas prices increased in recent years, but so has gas price volatility. Figure ES-2 shows the annualized 90-day standard deviation of daily percentage

reference case gas price forecasts because they are publicly available, have been widely vetted, and are commonly used by the EIA and others as a “base case” price scenario in policy evaluations and modeling exercises. As a control, we also look at other non-EIA gas price forecasts that may not suffer from this ambiguity.

changes in gas futures prices, along with its one-year (i.e., 252-day) moving average to smooth out seasonality. Though highly seasonal in nature, the general increase in volatility, particularly since 1996, is clear. Near-record-high volatility, combined with price levels that are more than double the historical average, mean that in absolute terms, an unprecedented number of dollars are now at risk.

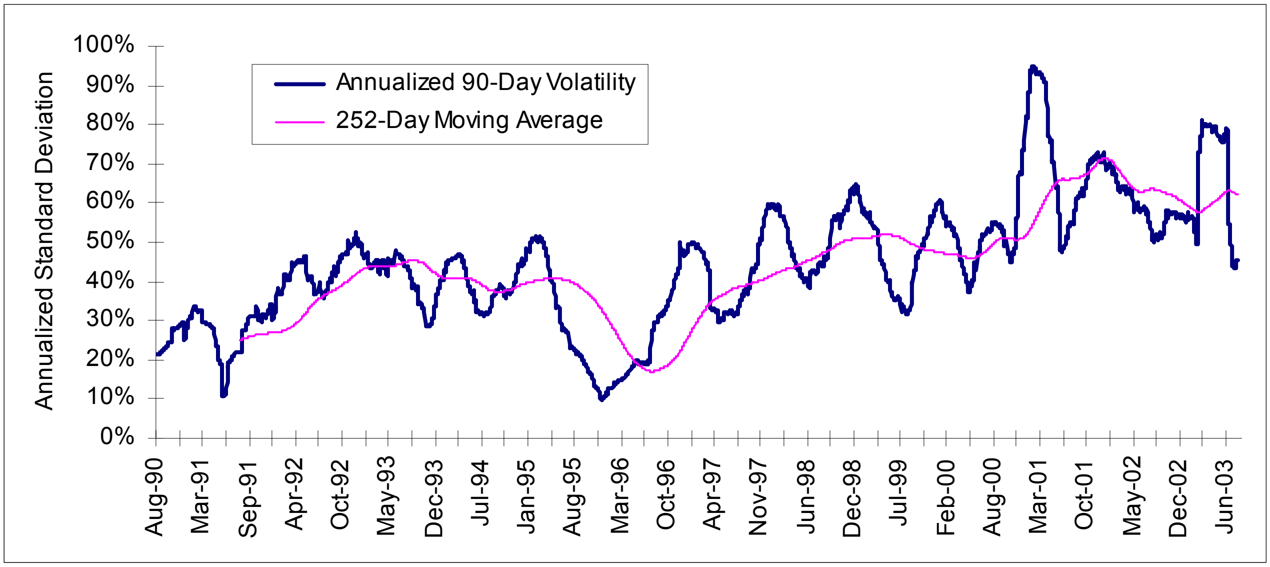

Figure ES-2. Historical Volatility of Natural Gas Futures Prices (Continuous 1st Nearby)

This is particularly noteworthy considering that gas price volatility, which has attracted a great deal of recent attention, is a major contributor to wholesale electricity price volatility. The cost of natural gas can account for *more than half* the levelized cost of energy from a new combined cycle gas turbine, and *more than 90%* of its operating costs (EIA 2001). Moreover, gas-fired plants are often the marginal units that set the market-clearing price for *all* generators in a competitive wholesale market, allowing natural gas price volatility to directly flow through to wholesale electricity price volatility.

Unless they are hedged, gas price increases can therefore directly impact competitive wholesale electricity prices, particularly if gas-fired units are on the margin. And with the market share of gas-fired generation projected to nearly double by 2025, the impact of gas price volatility on wholesale electricity price volatility is likely to increase as well. Clearly, the variability of gas prices poses a major risk to both buyers and sellers of gas-fired generation.

Traditional Natural Gas Hedging Instruments Can Be Used to Mitigate Risk

Renewable energy resources such as wind, geothermal, biomass, solar, and hydro power are often sold on a fixed-price basis, providing a hedge against volatile natural gas prices. Nonetheless, it is also true that natural gas price risk can be hedged through traditional gas-based hedging instruments. In order to achieve a fuel price risk profile similar to that of fixed-price renewable generation, either the buyer (under spot, indexed, and tolling electricity contracts) or seller (under fixed-price electricity contracts) of gas-fired generation must hedge away natural gas price risk.

Accordingly, to hedge natural gas price risk, a retail electricity supplier can either invest in renewable generation (which is immune to gas price risk), choose among a number of gas-based financial and physical hedging instruments, or purchase *fixed-price* gas-fired electricity (in which case the *generator* may wish to hedge using gas-based financial or physical instruments).[3] Financial gas-based 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.

As shown below in Figure ES-3, each of these hedging instruments falls into one of two categories: those creating a flat payout pattern that is immune to price movements in either direction (gas futures, swaps, and fixed-price physical supply, as well as fixed-price renewable generation), and those creating a contingent payout pattern that protects against adverse price movements while allowing participation in favorable price movements (gas options and storage). In other words, all of the hedging instruments under consideration can protect gas consumers against a gas price increase, but only options and storage allow the consumer to benefit from a gas price decrease as well.

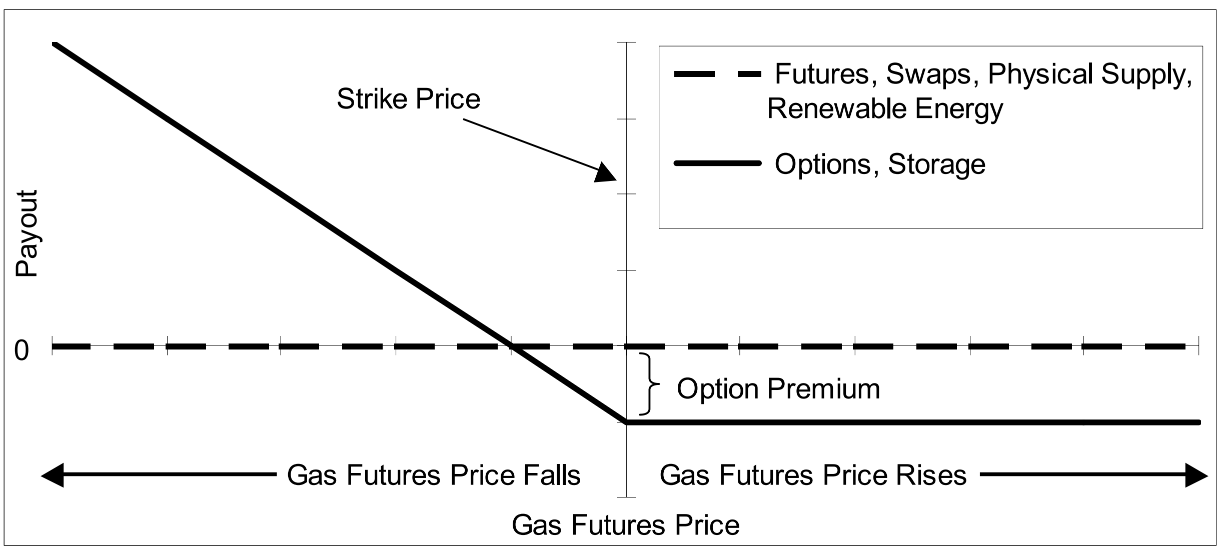

Figure ES-3. Payout Patterns for Various Hedging Instruments (hedge plus underlying)

To fairly evaluate fixed-price renewable and variable-price gas contracts on an apples-to-apples basis (presuming that long-term price stability is valued), we must look to those instruments that provide a hedged payout pattern similar to that of renewables – i.e., flat and symmetrical, immune to both gas price increases and decreases. As shown in Figure ES-3, such instruments

[3] Similarly, investments in energy efficiency (e.g., through demand-side management), or even coal or nuclear power (with fuel costs that are quite stable compared to natural gas), may provide an equivalent natural gas price hedge. Though not explicitly targeted as such, much of the discussion in this paper is also applicable to these other energy, or demand reduction, resources.

include gas futures, swaps, and fixed-price physical supply contracts, but not options or storage. The prices that can be locked in through these instruments are therefore the appropriate fuel price input to modeling and planning studies that compare – either explicitly or implicitly – renewable to gas-fired generation (again, presuming that long-term price stability is valued).

Forward Gas Prices Have Traded at a Premium to EIA Reference Case Price Forecasts

As has been noted, however, utilities and others conducting such studies tend to rely primarily on uncertain long-term forecasts of spot natural gas prices, rather than on prices that can be locked in through futures, swap, or fixed-price physical supply contracts (i.e., "forward prices"). This practice raises a critical question: how do the prices contained in uncertain long-term gas price forecasts compare to actual forward prices that can be locked in? If forward prices systematically differ from long-term price forecasts (e.g., if there is a cost to hedging, or if the forecasts are out of tune with market expectations), then the use of such forecasts in resource acquisition, planning, and modeling exercises will yield results that are biased (again, assuming that long-term price stability is desirable) in favor of either renewable (if forwards < forecasts) or natural gas-fired generation (if forwards > forecasts).

The data necessary to conduct this analysis are deceptively simple: a forward gas price and a gas price forecast, ideally generated at the same time. While long-term gas price forecasts are relatively easy to come by (e.g., the EIA forecasts are publicly available and updated every year), long-term forward prices – and in particular those of sufficient duration to be of interest, given the 15-25 years of relative price stability offered by most contracts for renewable generation – present a greater challenge. Despite our best efforts to obtain a larger sample, our analysis is limited to comparisons from the past three Novembers (November 2000-November 2002), and for terms not exceeding 10 years. Specifically, our limited sample of forward contracts and price forecasts includes:

- 2-, 5-, and 10-year natural gas swaps offered by Enron in November 2000 and 2001, compared to reference case natural gas price forecasts from the Energy Information Administration's (EIA) *Annual Energy Outlook 2001* and *2002*, respectively;
- the six-year NYMEX natural gas futures strip from November 2002, compared to the reference case gas price forecast contained in *Annual Energy Outlook 2003*, and;
- a seven-year physical gas supply contract between Williams and the California Department of Water Resources signed in November 2002, again compared to the reference case gas price forecast contained in *Annual Energy Outlook 2003*.

Each of these comparisons reveals that forward natural gas prices have traded above EIA reference case price forecasts during this three-year period, sometimes significantly so. Figure ES-4 consolidates the resulting premiums (in terms of \$/MMBtu and ¢/kWh, assuming a heat rate of 7,000 Btu/kWh) from each of these comparisons into a single graph.

As shown, the magnitude of the empirically derived premiums (i.e., relative to EIA reference case forecasts) varies from year to year, contract to contract, and by contract term, ranging from

$0.4-$0.8/MMBtu ($0.6/MMBtu on average), or 0.3-0.6¢/kWh (0.4¢/kWh on average).[4] One cannot easily extrapolate these findings beyond the last three Novembers, or to contract terms longer than those examined. Nonetheless, it is at least apparent that utilities and others who have conducted resource planning and modeling studies based on EIA reference case gas price forecasts over the past three years have produced "biased" results (i.e., presuming that long-term price stability is valued) that favor variable-price gas-fired over fixed-price renewable generation, potentially to the tune of ~0.3-0.6¢/kWh on a levelized basis.

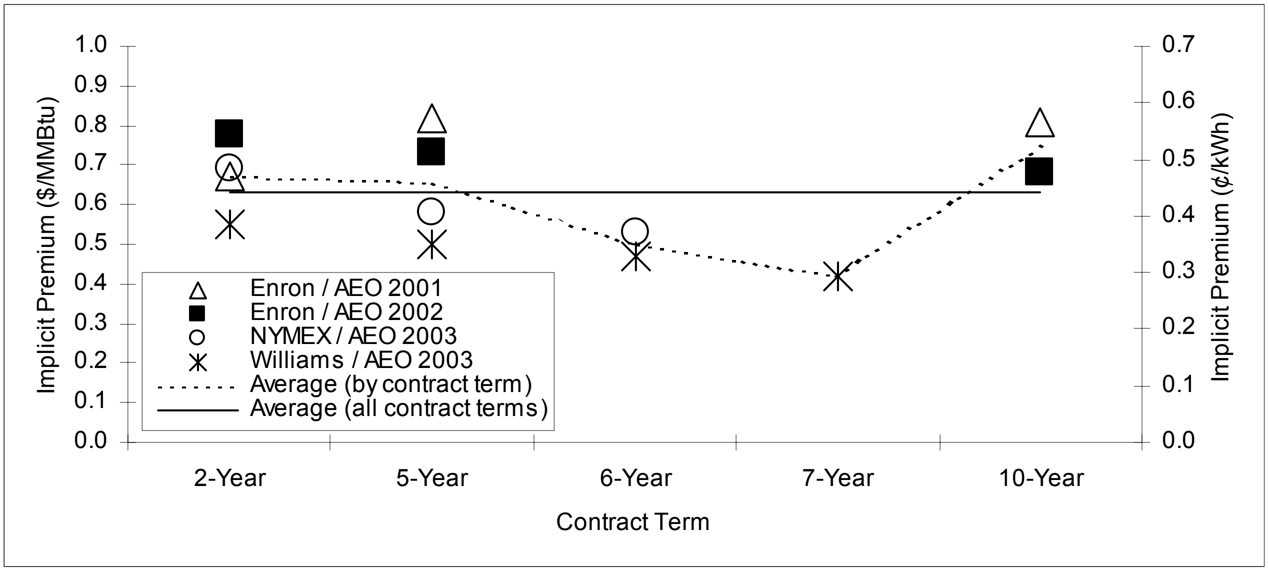

Figure ES-4. Composite Premiums in $/MMBtu and ¢/kWh (assuming 7,000 Btu/kWh)

Many Other Gas Price Forecasts Have Been Even More "Biased" Over the Last Three Years

Given that they are publicly available, highly documented, and widely reviewed and used (even by utilities) in modeling exercises and resource planning processes throughout the country, EIA reference case gas price forecasts are a reasonable starting point for our purposes. The EIA's forecasts, however, are by no means the only long-term gas price forecasts available to market participants. Among others, PIRA Energy Group, DRI-WEFA, and Energy and Environmental Analysis (EEA) all provide proprietary long-term gas price forecasts to utilities and others.

Obviously, unless these other forecasts are in close agreement with EIA reference case forecasts, the spread between them and forward gas prices will be different from that measured against EIA reference case forecasts. In order to assess how the premiums presented in Figure ES-4 would change had we compared forward prices to some forecast other than the EIA's, we looked at a number of different long-term gas price forecasts, sourced from the EIA's own forecast comparisons (contained in each year's *Annual Energy Outlook*), as well as from various utility integrated resource plans. With few exceptions, the EIA reference case forecast has generally

[4] We emphasize that these premiums are benchmarked against EIA reference case gas price forecasts, and that the magnitude – and perhaps even the sign – of the premiums will change if our sample of forward prices is compared to price forecasts that differ from the EIA reference case.

been higher – and often substantially so – than most other forecasts that have been used by utilities and others trying to predict gas prices over the last three years.

These findings suggest that the premiums observed relative to the EIA reference case forecasts would be *even larger* when comparing forward prices to some of the other commonly used gas price forecasts. For example, had we compared the November 2001 10-year natural gas swap to the gas price forecast contained in Idaho Power's resource plan, we would have observed a 10-year levelized premium of $1.29/MMBtu – i.e., *nearly twice as large* as the $0.68/MMBtu benchmarked against the EIA reference case forecast. This translates to a 0.9¢/kWh difference at an aggressive heat rate of 7,000 Btu/kWh; had Idaho Power opted to use forward market data rather than forecast data, comparisons between renewable and gas-fired generation may have looked significantly different. With most other forecast comparisons yielding similar results (though not as large in magnitude), it is clear that utilities and others that have used these other (i.e., non-EIA) forecasts to compare fixed-price renewable to variable-price gas-fired generation over the past three years have obtained results that are *even more* "biased" in favor of gas-fired generation than those resulting from EIA-based reference case comparisons (again, presuming that long-term price stability is desirable).

Possible Explanations for the Empirical Premiums Between Forwards and Forecasts

How can one explain the existence of price premiums as high as $0.8/MMBtu over 10 years relative to EIA reference case gas price forecasts, or *even higher* relative to other gas price forecasts? At least three different explanations could either partially or wholly account for such sizable differences between natural gas forwards and forecasts:

1) **Hedging is not costless.** If this is true, then one might expect forward natural gas prices to trade at a premium relative to industry-standard forecasts of future spot natural gas prices, with the premium representing the incremental cost of hedging. Such incremental costs could reflect the presence of a risk premium, caused either by *negative net hedging pressure* (i.e., gas consumers hedging more than gas producers) or *systematic risk in natural gas prices*, as measured by the Capital Asset Pricing Model (CAPM). Alternatively, the incremental cost of hedging could reflect high *transaction costs*, manifested in wide bid-offer spreads that ensure that the long (short) hedger always pays (receives) more (less) than the "true" (e.g., mid-market) price. Under this explanation (that hedging is not costless), the premiums presented in Figure ES-4 might be considered the "hedge value" of renewable generation; i.e., renewable generation provides price stability without incurring these "incremental" hedging costs.

2) **The forecasts are out of tune with market expectations.** Under this explanation, the gas price forecasts (not just the EIA's reference case, but instead virtually all of the forecasts we have examined) themselves are at issue, and are biased downwards relative to the market's expectations of future gas prices at least over the last three years. If this is true, then our empirical observations of premiums may not necessarily indicate that there is an incremental cost of hedging per se. In other words, forward prices may in fact be unbiased estimators of future spot prices, and the premiums we have observed may simply be due to the use of

forecasts that have been seriously out of tune with market expectations over the last three years. This, of course, calls into question the use of these forecasts for *any* purpose over the last three years, and strongly suggests replacing forecast prices with forward prices where available.

3) **Other data issues are driving the premium.** Two other data problems might also be of some concern. First, the forward prices we sampled might be distorted upwards (e.g., due to thin markets and/or price manipulation), which could artificially create or inflate a premium over price forecasts. Second, if we sampled forward prices earlier or later in time than when the forecasts were generated, then the observed premiums could simply be the result of a fundamental change in market expectations in the interim.

Each of these three potential explanations for the existence of empirical premiums is theoretically plausible, yet perhaps not fully satisfactory on its own; it is perhaps more likely that two or more of these (and maybe other) explanations working in combination are driving our empirical findings of a premium.

Regardless of the explanation for (or interpretation of) our empirical findings, however, the basic implications of our study remain the same: *one should not blindly rely on gas price forecasts when comparing fixed-price renewable to variable-price gas-fired generation contracts.* If there is a cost to hedging – whether related to net hedging pressure, CAPM, transaction costs, or some combination of the three – gas price forecasts do not capture and account for it. Alternatively, if the forecasts are at risk of being biased or out of tune with the market, then one certainly would not want to use them as the basis for investment decisions or resource comparisons if a better source of data (i.e., forwards) existed. Accordingly, assuming that long-term price stability is valued, in both cases the most comprehensive way to compare resource options would be to use forward natural gas price data as opposed to natural gas price forecasts. Over the last three years, at least, it appears as if the use of forward gas prices would have significantly shifted the balance away from natural gas and toward renewable energy, relative to forecast-based comparisons.

Implications for Resource Planners, Analysts, and Policymakers

These findings have important implications for utility resource planners, energy modelers and analysts, and policymakers:

Utility Resource Planners

While our examination of utility integrated resource plans revealed that many utilities do in fact incorporate actual forward market prices (i.e., the price at which they could lock in gas prices) into their gas price forecasts, they typically do so for only the first few years of what are commonly 20-year forecasts. Since the value of price stability does not disappear after a few years, further action may be warranted.

Assuming that long-term price stability is valued, what steps can a utility or, more generally, anyone comparing fixed-price renewable to variable-price natural gas generation, take to move towards an apples-to-apples comparison? Because of the challenges in extrapolating our findings to other forecasts, hedge durations, and time periods, we *do not* recommend blindly adding \$0.4-\$0.8/MMBtu, or 0.3-0.6¢/kWh, to any forecast, for any duration. We emphasize that these premiums were derived relative to EIA reference case gas price forecasts over a limited three-year period that may or may not represent "normal" market conditions, and for contract terms ranging from 2-10 years. Any attempt to directly apply these particular premiums outside of these parameters may be questionable, especially if better data is available at the time.

Because of the difficulty in extrapolating our results to different circumstances, below we develop process recommendations for resource planners. At least three approaches are possible:

1) **Use and extend the forward curve for natural gas:** As noted earlier, utilities have already begun to incorporate gas forward prices into their gas-price forecasts. This is a good start, but many of these utilities only rely on a year or two of forward price data. Subject to data availability, utilities (or others making resource comparisons) could extend the period over which their resource plans (or comparisons) rely on actual forward market gas prices rather than uncertain price forecasts. Given the availability of NYMEX futures price data, extending the use of forward prices to at least 6 years would seem like a first step. Beyond 6 years, forward price data may be harder to come by. Where forward price data from actual contracts are not publicly available, utilities and others may have access to (or be in a position to solicit) data that are not in the public domain; broker quotes may also suffice as a way of extending the use of forward data to 10 or even 20 years.

2) **Place the onus on the generator:** Natural gas-fired generators may be willing to internalize any cost of hedging (or alternatively, take on fuel price risk) and offer a long-term fixed-price electricity contract, much like renewable energy typically provides. While fixed-price renewable energy may still have some incremental "hedge value" (from placing downward pressure on gas prices, and potentially mitigating credit risk), a fixed-price gas-fired electricity contract is otherwise comparable to fixed-price renewable energy, thereby obviating the need for a utility or regulator to collect forward gas price data for the purpose of substituting into a forecast. Along these lines, utilities could follow the example of Xcel Energy in Minnesota, which – as directed by the Minnesota PUC – has worked with stakeholders to develop a method for unbiased treatment of renewable generation in its bid evaluation process. Specifically, in all-source solicitations, Xcel requires "that bidders who submit fuel-indexed or tolled fuel pricing in a proposal must also submit an otherwise identical proposal that contains fixed fuel pricing for at least 10 years." (Xcel Energy 2001) Though obtained during the solicitation rather than the planning phase, this information, along with other provisions, enables Xcel to more closely approximate a true apples-to-apples comparison between renewable and other forms of generation.

3) **Adjust the forecast:** Finally, as a last resort, if forward market prices are not available over the entire planning horizon, and soliciting comparable fixed-price electricity bids from gas-fired generators is not realistic, utilities may wish to adjust forecasted gas prices upwards to account for the fact that forward prices have, potentially for reasons discussed above, traded above price forecasts over the past three years. While the analysis in this report suggests that

an adjustment ranging from \$0.4-\$0.8/MMBtu (0.3-0.6¢/kWh at a heat rate of 7,000 Btu/kWh) is a reasonable starting point, we emphasize that these premiums were calculated with respect to EIA reference case price forecasts over the past three years, for terms ranging from 2-10 years. If using a different base gas price forecast, a higher or lower adjustment may be warranted. Likewise, this historically derived premium may well vary in the future, and may vary with contract terms above 2-10 years. For these reasons, the two previous approaches are preferable to this one. That said, if the two previous approaches are not possible, this approach may still be better than simply relying on forecast data, which – at least over the last three years – has been shown to be significantly below forward prices.

Energy Modelers and Analysts

It remains to be seen which, if any, of the explanations for empirical premiums discussed in Chapter 6 are "correct," and the implications for energy modelers and analysts vary based on the explanation under consideration. If there truly is a cost to hedging natural gas price risk with traditional instruments, and renewable energy can mitigate fuel price risk at a cost that is lower than that incurred through those traditional hedging instruments (and the market recognizes this), then the supply of renewable generation may increase at faster rate than that estimated by current national energy forecasts, leaving forecasts of renewable generation biased downwards. If instead the premiums observed in Chapter 4 are attributable to gas price forecasts that are biased downwards or are otherwise inconsistent with market expectations of future spot prices, then energy modelers will no doubt want to investigate the cause of the discrepancy between their forecasts of natural gas prices and the market's expectations of those same prices. In either case, if long-term price stability is valued, energy analysts should ideally compare the cost of renewable generation against the cost of gas-fired generation using forward gas prices as the relevant fuel cost.

Policymakers

While the root cause of the empirical premiums we have observed in this paper remains unclear, the fact that renewable generation provides long-term price stability is beyond reproach. As long-term price stability is undoubtedly valued to some degree by end-use customers, the "hedge value" of renewable generation should help to justify continued and new policy support for renewables. For example, if future work confirms the hedge value of renewable energy, policymakers should begin to explore practical mechanisms (such as those discussed above) 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.

1. Introduction

1.1 Overview and Purpose

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 massive state budget deficit, while the commensurate price decrease over the remainder of 2001 left the state holding over-priced power contracts, many of which have been re-negotiated or litigated. Though an extreme example, California is not alone in its dependence on gas-fired generation and accompanying exposure to fuel price volatility: New England, New York, and Texas are all heavily gas-dependent, for example, and many other states are becoming increasingly so.

Against this backdrop, renewable energy resources such as wind, geothermal, biomass, solar, and hydro power, which by their nature are immune to natural gas fuel price risk, provide a real economic benefit. Unlike many contracts for natural gas-fired generation, renewable generation is typically sold under *fixed-price* contracts. Assuming that electricity consumers value long-term price stability,[1] a utility or other retail electricity supplier that is looking to expand its resource portfolio (or a policymaker interested in evaluating different resource options) should compare the cost of fixed-price renewable generation 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 carry no natural gas fuel price risk, and if the market values that attribute, then the most appropriate comparison is to the *hedged* cost of natural gas-fired generation.[2]

Later in this paper, however, we show that utilities and others often compare the costs of renewable to gas-fired generation using as their fuel price input long-term gas price forecasts that are inherently uncertain, rather than long-term forward prices that can actually be locked in. This practice raises the critical question of how these two price streams compare. If they are similar, then one might conclude that forecast-based modeling and planning exercises are in fact approximating an apples-to-apples comparison, and no further consideration is necessary. If, however, natural gas forward prices systematically differ from price forecasts, then the use of such forecasts in planning and modeling exercises will yield results that are biased in favor of either renewable (if forwards < forecasts) or natural gas-fired generation (if forwards > forecasts).

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[1] 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.

[2] Investments in energy efficiency (e.g., through demand-side management) could also reduce exposure to volatile gas prices, as could investments in coal or nuclear power (whose fuel costs are more stable than the cost of natural gas). Though not explicitly targeted as such, much of the discussion in this paper is also applicable to these other energy, or demand reduction, resources.

Building upon earlier analysis of fuel price risk (see Text Box 1), in this report we compare the cost of hedging natural gas price risk through traditional gas-based hedging instruments (e.g., futures, swaps, and fixed-price physical supply contracts) to contemporaneous forecasts of spot natural gas prices, with the purpose of identifying any systematic differences between the two. Although our data set is quite limited, we find that over the past three years, forward gas prices for durations of 2-10 years have been considerably higher than most natural gas spot price forecasts, including those developed by the Energy Information Administration (EIA). For example, the difference (on a levelized basis) between forward prices and the EIA reference case spot price forecasts has ranged from \$0.4-0.8/MMBtu (\$0.6/MMBtu on average).[3] This difference is striking, and implies that resource planning and modeling exercises based on these forecasts over the past three years have yielded results that are biased in favor of gas-fired generation (again, presuming that long-term price stability is desirable). As discussed later, these findings have important ramifications for resource planners, energy modelers, and policymakers.

1.2 Why Focus on Natural Gas Price Risk?

While this paper focuses exclusively on natural gas fuel price risk, we readily acknowledge that both renewable and natural gas-fired generation involve many different types of risks, including the risk of fuel supply interruptions, the risk that generating units will not meet their contractual performance requirements, the risk that future environmental regulations will impose additional costs, and the risk that the output of the generating unit will be variable and/or unpredictable.[4] Our exclusive focus on natural gas fuel price risk is driven by a number of factors:

- Gas price volatility, which has attracted a great deal of recent attention, is a major contributor to wholesale electricity price volatility. The cost of natural gas can account for *more than half* the levelized cost of energy from a new combined cycle gas turbine, and *more than 90%* of its operating costs (EIA 2001). Moreover, gas-fired plants are often the marginal units that set the market-clearing price for *all* generators in a competitive wholesale market, allowing natural gas price volatility to directly flow through to wholesale electricity price volatility.
- Unlike some other risk types (e.g., fuel supply risk), fuel price risk clearly affects gas-fired generation to a far greater degree than it does renewable generation, enabling a clear delineation to be drawn between the two.[5]
- In addition, unlike some other risk types (e.g., environmental compliance risk), fuel price risk can easily be hedged through conventional means (e.g., natural gas futures, options,

[3] Although the preface to the *Annual Energy Outlook 2003* from the EIA begins by stating that the document "presents mid-term *forecasts* of energy supply, demand, and *prices* through 2025…" (italics added), and both italicized terms can be found sprinkled liberally throughout the document, reviewers of a draft of this report from the EIA contend that, in fact, the EIA *projects* (rather than *forecasts*) energy *costs* (rather than *prices*). We discuss this subtle distinction later in Section 6.2; until then, we simply note that we will use the terms *price* and *forecast* (rather than *cost* and *projection*) throughout this document, at least in part because we refer to other price forecasts than those generated by the EIA.

[4] For a detailed investigation into the different types of risks inherent in contracts for gas-fired and renewable generation, see Bachrach et al. 2003.

[5] This is also true for environmental risk, which is not covered in this paper. Also note that some renewable energy resources – biomass in particular – are subject to fuel price risks of their own. Nonetheless, none of the renewable energy sources are subject to natural gas price risk per se.

swaps, physical supply) at least over short durations, providing a clear benchmark against which the price stability of renewables can be measured.

- Markets and analysts are beginning to value some of the other types of risk inherent in both fossil-fueled and renewable generation. For example, utilities and independent system operators sometimes financially penalize wind power to account for the cost of managing its intermittence. On the other hand, the fuel price risk mitigation benefits inherent in renewable energy – though widely proclaimed by renewable energy advocates – have, with a few notable exceptions (see Text Box 1), been recognized only in a qualitative fashion to date. In this sense, the cost of fuel price risk (or conversely, the benefit of fuel price risk mitigation) is a major missing part of the overall equation, and therefore deserves attention.
- Finally, on a more practical level, natural gas price forecasts and forward price curves – i.e., the data necessary to conduct our analysis – are, to some degree, readily available, whereas data pertaining to some of the other risk types are considerably harder to come by. For example, data on the long-term forward curve for wholesale electricity prices, which would be required to assess the cost of hedging many of the risk types in aggregate, are scarce. Similarly, empirical data on the actual cost of hedging future environmental risk exposures is not available.

While our focus is therefore exclusively on fuel price risk, there are at least two items related to fuel price risk that are *not* considered in our analysis, but are nonetheless worth noting at the outset:

1) First, as the market share of renewable generation increases, relative demand for natural gas among gas-fired generators is likely to drop. As a result of this inward shift in the demand curve for natural gas, wellhead prices are expected to decline, thereby benefiting end-users of natural gas *in all sectors* (i.e., not just the electricity sector). In other words, unlike conventional "financial" hedges (e.g., gas futures, forwards, and swaps), which merely *shift* gas price risk to those best able to bear it, the "physical" hedge of renewable electricity actually *reduces* gas price risk.

   The Energy Information Administration (EIA) and others who have modeled the cost of a national renewables portfolio standard (RPS) designed to increase the market penetration of renewables have often concluded that the resulting benefit of lower natural gas prices to ratepayers is significant, and in some cases almost completely offsets the increase in electricity prices from incorporating above-market renewable generation (St. Clair et al., forthcoming). While this effect is the result of a transfer payment rather than a societal benefit (i.e., ratepayers benefit at the expense of gas producers), and is not included in our analysis, it is worth noting nonetheless, as policy is often formulated with ratepayers in mind.

2) Second, long-term fixed-price natural gas contracts (i.e., "conventional" hedges, such as gas forwards and swaps) may carry more credit risk than do fixed-price renewable energy contracts of similar duration. For example, once a wind plant is operating and under contract, the owner of the plant is unlikely to default on the contract due to credit concerns (at least in part because the capital investment has already been made, and operating costs

are low and stable). A long-term fixed-price natural gas contract, on the other hand, may be a prime candidate for contract default, mainly because of high price volatility in the underlying commodity, and the fact that many financial gas price hedges are not directly linked to physical supply. Thus, long-term fixed-price renewable energy contracts may provide incremental value over natural gas forward and swap contracts in the form of reduced credit risk. This difference – which is not included in our analysis – may become increasingly important over longer contract terms of 15-25 years.

1.3 Report Organization and Summary

Following this introduction, **Chapter 2** provides basic background information on gas price volatility and its effect on, as well as treatment in, different types of electricity contracts. We find gas price volatility to be a major source of risk in electricity contracts.

Chapter 3 explores various ways to hedge natural gas price risk through traditional gas-based hedging instruments, including futures (or forwards), swaps, options, fixed-price physical supply, and storage. Our purpose is three-fold: (1) to familiarize the reader with the traditional gas-based instruments that can be used to hedge price risk; (2) to determine which of these instruments create a hedged exposure similar to that provided by renewables (i.e., immune to gas price movements in either direction); and (3) to characterize the "cost" of each instrument. We find that natural gas options and storage are not particularly relevant to our analysis, and that instead the price of a futures, swap, or fixed-price physical supply contract provides the relevant point of comparison to gas price forecasts.

Chapter 4 compares actual natural gas forward market prices (from natural gas swap, futures, and fixed-price physical supply contracts) over the past three years to contemporaneous long-term natural gas price forecasts generated by the EIA in its *Annual Energy Outlook* (AEO) publication series. Applying this methodology to an admittedly small sample of data, we find that over the past three years, natural gas forward prices have exceeded the AEO reference case price forecasts by an amount ranging from \$0.4-\$0.8/MMBtu (\$0.6/MMBtu on average), depending on the contract, the contract term, and the year of comparison. At an aggressive heat rate of 7,000 Btu/kWh, this "premium" equates to 0.3-0.6¢/kWh (0.4¢/kWh on average). We also search for a term structure in the premium, which might allow us to extrapolate the premium beyond the relatively brief contract terms examined (e.g., from 2-10 year natural gas hedges to 20-year hedges), but are unable to draw any definitive conclusions in this regard.

Chapter 5 compares the EIA reference case gas price forecasts used in Chapter 4 to other publicly available long-term gas price forecasts. Our intent is to discover whether the "premiums" observed in Chapter 4 would be more or less sizable if benchmarked against other frequently used natural gas price forecasts. We find that in recent years the EIA reference case forecast has typically been higher – and often substantially so – than most other natural gas price forecasts that are commonly used by utilities and others when evaluating different resource options. This finding suggests that the premiums observed relative to the EIA forecasts in Chapter 4 would be even *larger* if the comparison were instead to a forecast other than the EIA's reference case. Utilities and analysts that have used these other (i.e., non-EIA) forecasts to

Text Box 1: A Brief Survey of Past Literature on Fuel Price Risk

Attempts to quantify the impact of fuel price risk, or similarly the value of resource diversification within a generation portfolio, date back to at least the late 1980s, and are largely coincident with the ascent of integrated resource planning. The literature blossomed in the early 1990s, prompted at least in part by California's investigation into the value of fuel diversity in its 1992 Electricity Report. While some work on this topic continued during the remainder of the 1990s, it was largely overshadowed by the onset of electric industry restructuring, and it was not until the California electricity crisis of 2000/2001 and the accompanying extreme price volatility in both gas and electric markets that there has been a resurgence of interest in fuel price risk.

Our review of the relevant literature over the past 15 years reveals that a number of different methods have been used to quantify fuel price risk or, similarly, the value of generation diversity. Most of the work can be loosely grouped into six broad categories: discounted cash flow analysis using risk-adjusted discount rates, decision analysis, options theory, portfolio theory, diversity indices, and empirical market-based comparisons. Our intent here is not to analyze this previous work in depth, but rather to very briefly describe each of these six methods and provide references to the most relevant works in each area.

Discounted Cash Flow Analysis Using Risk-Adjusted Discount Rates

Awerbuch (1993, 1994) has been the foremost proponent of this method, which involves taking a financial, rather than "engineering economics," perspective to traditional project valuation using net present values. Instead of simply discounting a project's net cash flow at the firm's weighted average cost of capital (WACC), cash flows are disaggregated and each individual cash flow (or grouping of similarly risky cash flows) is discounted using *risk-adjusted* discount rates. Risk-adjusted discount rates are derived from the Capital Asset Pricing Model (see Section 6.1.2 of this paper for a description of CAPM), or alternatively based on the general risk profile of the cash flow stream being evaluated (e.g., largely fixed-price expenses such as fixed O&M resemble debt payments, and so are discounted at the firm's after-tax cost of debt). Awerbuch finds that, when valued using risk-adjusted discount rates, capital-intensive renewable generation easily out-competes more risky gas-fired generation. Interestingly, these results are not overly sensitive to the CAPM-derived beta of natural gas: even if one assumes that gas prices can be contractually locked in for 30 years *at no premium* (i.e., beta = 0), such a cash outlay should be discounted as a debt-equivalent obligation at the firm's cost of debt, rather than its higher WACC. Awerbuch (2003) shows that this shift from WACC to debt-equivalent discount rates accounts for *more than half* of the total value derived from shifting to risk-adjusted discount rates that are based on historical spot price volatility (i.e., with beta < 0).

Decision Analysis

A number of analysts have compared hypothetical utility investments in renewable and gas-fired generation by constructing decision trees that model a range of future scenarios, varying in terms of fuel prices, load growth, construction costs, plant availability, or environmental costs. Some studies (e.g., Cadogan et al. 1992) calculate expected values at each branch of the tree by assigning probabilities to each outcome, whereas others (e.g., Brower et al. 1996) assign a mean and standard deviation to each variable (assuming a normal distribution of outcomes), and then run Monte Carlo simulations.

Decision trees and the scenarios they represent can be evaluated using at least three different methods: discounted cash flow analysis (where risky cash flows are discounted at risk-adjusted discount rates), options valuation (where risk-neutral cash flows are discounted at the risk-free rate), or certain equivalence (where certain cash flows are discounted at the risk-free rate). While each of these methods should yield identical results if properly executed (Hoff 1997, Brealey and Meyers 1991), decision analysis has often employed certain equivalence, which measures affected parties' (in this case ratepayers) aversion to risk. The "certain equivalent" is the amount that a ratepayer, facing an uncertain expected payment for future electricity usage, would rather pay with certainty; risk aversion is the difference between the certain equivalent and the uncertain expected payment. Much of the testimony in California's 1992 Electricity Report proceedings relied on some form of certain equivalence to derive risk aversion coefficients and risk premiums (PG&E 1992, SDG&E 1992); others, such as Brower et al. (1996) have also taken this approach.

(continued from previous page)

Options Theory

Based on the notion that the premium paid for price certainty should be no higher than the cost of purchasing equivalent protection through alternative means (a notion also fundamental to our approach in this paper), Brathwaite and Gopal (1992) utilize options theory, and in particular the Black-Scholes model for valuing options, to derive the price of a basket of financial options that protect consumers against unfavorable gas price outcomes (i.e., rising prices). Although innovative, their analysis fails to recognize that options provide an asymmetrical payout pattern that is not directly comparable to the symmetrical payout pattern that renewables and other diversifiers (e.g., fixed-price contracts) typically provide (see Figure 6 of this paper, and the discussion surrounding it). Kahn and Stoft (1993) more accurately use Black-Scholes as a means of valuing a long-term power contract by calculating the theoretical value of a basket of options whose cash flows replicate those of the long-term contract; they also use it to prove that the risk-adjusted gas discount rate is less than the risk-free rate. Finally, we include the work of Owens (2003a, 2003b) here because options play a central role in his analysis, although his approach could perhaps more accurately be characterized as scenario analysis. Specifically, he calculates the value of locking in gas prices at $4/MMBtu through 2020 under low, medium, and high gas price scenarios, with results varying by scenario. Call and put options with $4/MMBtu strike prices are bought and sold to create a strip of synthetic futures positions whose costs can be calculated with respect to the various gas price forecasts for each future delivery month.

Portfolio Theory

Feldman (1997), Humphreys and McClain (1998), Awerbuch (2000), Hoff (2002), and Awerbuch and Berger (2003) have applied the basics of modern portfolio theory, which is widely used in the financial world to optimize investment portfolios, to the electricity sector. Portfolio theory considers the expected returns (or costs) and covariance of returns (or costs) of multiple assets to construct an "efficient frontier" of portfolios representing the full range of optimal risk/return tradeoffs. Awerbuch finds that by introducing "riskless" renewable technologies to the portfolio, one can construct a portfolio that is *superior to* the otherwise efficient frontier (i.e., higher return for a given amount of risk, or lower risk for a given return).

Diversity Indices

Drawing a distinction between *risk* (full set of possible outcomes known, able to assign meaningful probabilities to each), *uncertainty* (full set of outcomes known, unable to assign meaningful probabilities), and *ignorance* (neither full set of outcomes nor meaningful probabilities known), Stirling (1994, 1998) postulates that electricity investment decisions are most accurately characterized by *ignorance*. As such, diversity is the best line of defense, and Stirling proposes the use of a *diversity index*, similar to the Shannon-Wiener index used in ecology to measure biodiversity, to judge the "risk" of generating portfolios. Feldman (1997) also investigates diversity indices, but finds them to be inferior to portfolio theory.

Empirical Market-Based Comparisons

This approach makes use of the wealth of information embedded in the market price of forward and futures contracts in order to derive estimates of risk. Awerbuch (1994) looked at a 20-year fixed-price gas contract to derive a risk-adjusted discount rate and provide supporting evidence for theoretical CAPM-based estimates. Hoff (1997) mentions such a "market comparisons" approach, but does not pursue it. In this paper we compare the cost of long-term natural gas swaps, futures contracts, and physical supply deals to long-term price forecasts in an attempt to determine whether there is a difference between the two that might be indicative of an incremental cost of locking in prices (i.e., hedging). One advantage of this approach is its simplicity and transparency; though we do consider CAPM while pondering several potential explanations for our empirical results, this market-based approach is not *dependent* on CAPM or any other theoretical construct, making it both accessible and replicable.

compare fixed-price renewable to variable-price gas-fired generation over the last three years have therefore made comparisons that are arguably even more biased in favor of gas-fired generation than those resulting from EIA-based comparisons (presuming that long-term price stability is desirable).

Chapter 6 discusses three possible explanations for our empirical findings. The first is that there may be a measurable *incremental* cost to hedging natural gas price risk, potentially resulting from some combination of: (a) negative net hedging pressure, (b) systematic risk in natural gas prices, or (c) high transaction costs. In this case, one might expect forward natural gas prices to trade at a premium relative to industry-standard forecasts of future spot natural gas prices, not only in the past but also into the future. The second possibility is that there is no incremental cost to hedging per se (i.e., forward prices are unbiased estimators of future spot prices), but that instead most gas price forecasts over the past three years have been biased downward or have been otherwise inconsistent with market expectations at the time. In this case, any observed premium between gas forwards and forecasts over the last three years would be due to natural gas price forecasts that were fundamentally out of tune with market expectations of future gas prices, calling into question the use of such forecasts in evaluating different resource options in the first place. Finally, we consider a third possibility that data issues, related to distorted forward prices or a critical discrepancy in timing between when the forecasts were generated and when the prices were sampled, are responsible for the observed premium. We find none of these three possibilities to be either fully satisfying or easily refutable; it may be that some combination of factors is at work. Regardless of the explanation, however, the fundamental implications of our analysis are largely unchanged: if long-term price stability is valued, then when comparing the costs of variable-priced gas-fired generation to fixed-price renewable generation, one should not rely on uncertain gas price forecasts as fuel price inputs. Instead, natural gas forward prices that can be locked in provide the proper point of comparison. Over the last three years, at least, it appears as if the use of forward gas prices would have significantly shifted the balance away from natural gas and toward renewable energy, relative to forecast-based comparisons.

Chapter 7 briefly summarizes and reflects upon our analysis, provides a simplified real-world example that demonstrates how using a forward price rather than a price forecast could have led to a large difference in resource acquisition decisions, and discusses the implications of this work for resource planners, energy modelers and analysts, and policymakers. It deserves reiteration that we find natural gas forwards to be priced above commonly used gas price forecasts over the last three years, and that the explanation for these empirical findings remains unclear; extrapolating this “premium” into future years must therefore be done with care. We offer three recommendations for how planners and electricity suppliers might incorporate forward gas prices when making resource comparisons: (1) simply extend the period over which their resource plans (or comparisons) rely on actual forward gas prices rather than uncertain gas price forecasts, (2) force bidders in all-source solicitations to provide the information necessary to evaluate gas-fired and renewable generation on an apples-to-apples basis (e.g., require gas-fired generators to offer pricing on a long-term, fixed-price basis), and (3) finally, as a last resort if (1) and (2) are not possible, adjust the forecast upwards based on informed analysis, including (but not limited to) the results from this report.

2. Natural Gas Price Volatility and its Impact on Electricity Contracts

According to the EIA (2003), natural gas combined-cycle and combustion turbine power plants accounted for 96% (138 GW out of 144 GW total) of the total generating capacity added in the U.S. between 1999 and 2002. Looking ahead, gas-fired technology is expected to account for 80% of the 428 GW of new generating capacity projected to come on line through 2025, increasing the nationwide market share of gas-fired generation from 17% in 2001 to 29% in 2025 (EIA 2003). This strong growth in gas-fired generation is expected to place the electricity sector on par with the industrial sector in terms of natural gas usage (at 33% and 34% of total end-use natural gas consumption in 2025, respectively).

With increasing competition for natural gas supplies, it is likely that gas prices will be as or more volatile than they have been in the past. And with the market share of gas-fired generation projected to nearly double by 2025, the impact of gas price volatility on wholesale electricity price volatility is likely to increase as well. This chapter examines gas price volatility from a number of perspectives: historically (Section 2.1), as projected by the options market (Section 2.2), as it translates into wholesale electricity price volatility (Section 2.3), and as allocated by different types of electricity contracts (Section 2.4).

2.1 Historical Gas Price Volatility

Figure 1 shows "first-nearby" natural gas futures prices on a daily basis going back to the inception of trading on the New York Mercantile Exchange (NYMEX) in April 1990.[6] While the "twin peaks" of December 2000 and February 2003 clearly dominate the graph and make the rest of the price history look comparatively tame, the reader should keep in mind that many of the "lesser" price spikes during the early 1990s represent doublings or more in price. In other words, near-term natural gas futures prices have been volatile since the very inception of trading.

[6] The term "first-nearby" simply indicates that the contract in question is the closest to expiration (i.e., the first in the line or "strip" of contracts extending out into the future). Because of their relatively short time to expiration (< 1 month in the case of natural gas), first-nearby futures prices (sometimes referred to as "prompt-month" or "spot-month" prices) are a close approximation of spot prices.

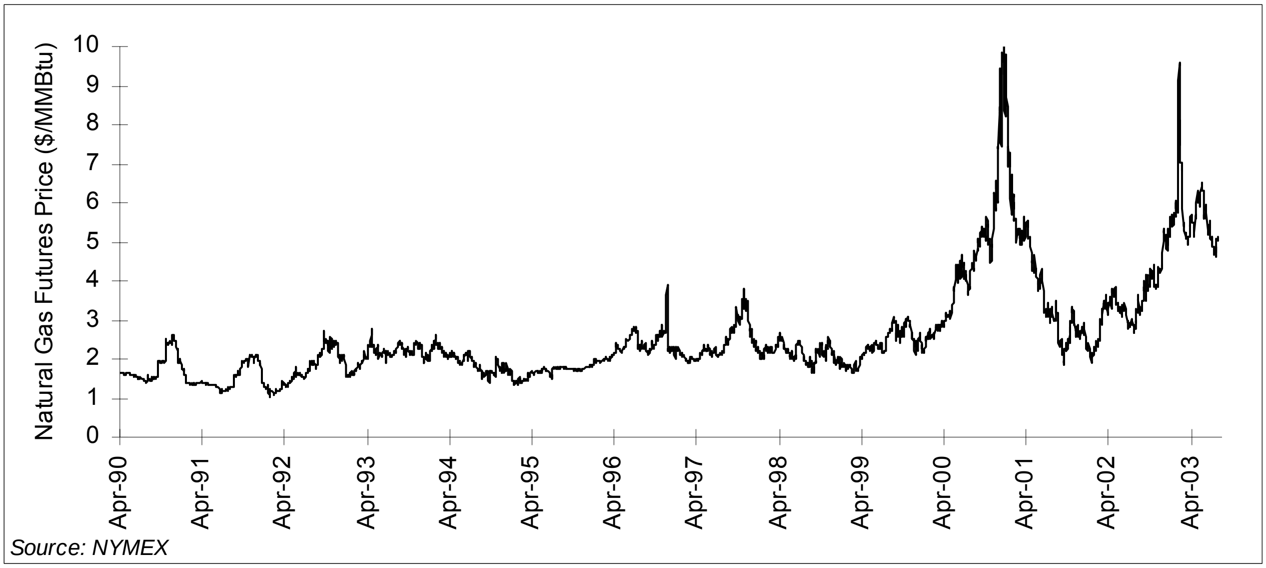

Figure 1. NYMEX Natural Gas Futures Prices (First-Nearby Contract)

In fact, natural gas exhibits higher price volatility than almost any other traded commodity, with the exception of wholesale electricity (EIA 2002, Hakes 1998, Graves et al. 2002, Farney 2001). Figure 2 compares the standard deviation of percentage changes in annual average prices for a number of different traded commodities over the past decade or so.[7] Absent sugar, whose high volatility is driven primarily by an isolated, yet severe, price spike in 2000/2001 (EIA 2002), the volatility of natural gas is second only to that of wholesale electricity, which is way off the graph in a class of its own at 389% (and is partly driven by gas price volatility). As a group, energy commodities tend to be the most volatile, followed by agricultural commodities, and finally financial products.

[7] Note that Figure 2, from the EIA (2002), was created prior to the latest natural gas price spike in February 2003.

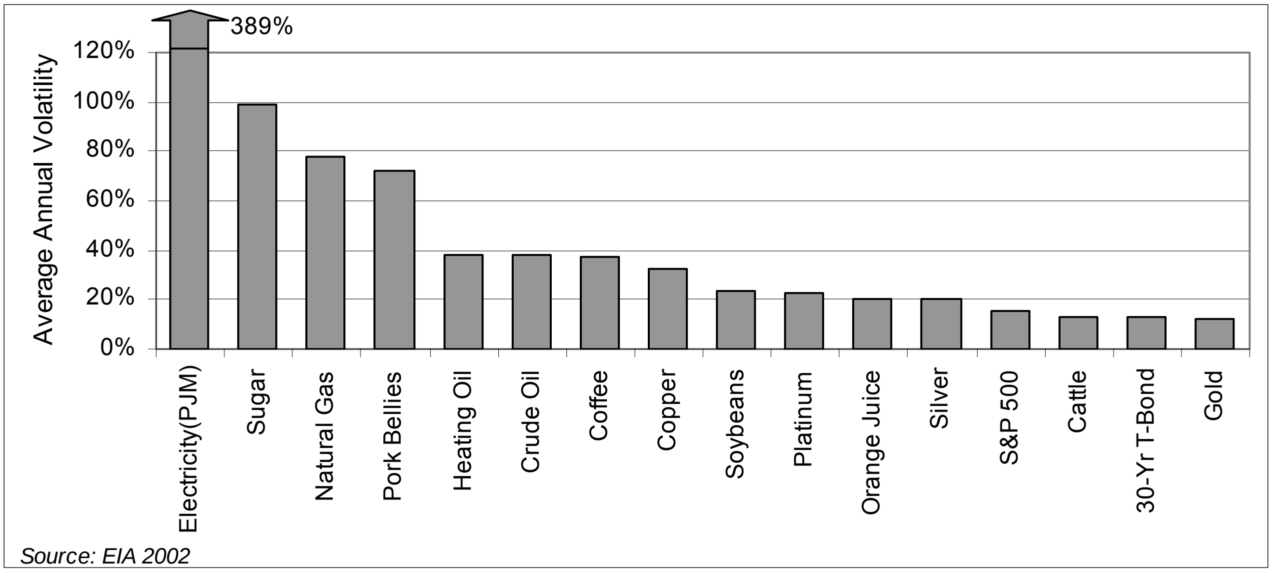

Figure 2. Average Spot Market Price Volatility for Selected Commodities

Not only has natural gas been one of the most volatile commodities historically, but, as implied by Figure 1, gas price volatility (in addition to gas prices themselves) has increased in recent years. Figure 3 shows the annualized 90-day standard deviation of daily percentage changes in the first-nearby "continuous" futures contract,[8] along with its one-year (i.e., 252-day) moving average to smooth out the seasonality. Though highly seasonal in nature, the general increase in volatility, particularly since 1996, is clear. Near-record-high volatility, combined with price levels that are more than double the historical average, mean that in absolute terms, an unprecedented number of dollars are now at risk.

[8] In other words, each point on the line represents the standard deviation of daily percentage changes in price over the most recent 90-day period, annualized by multiplying by the square root of 252 (i.e., the number of trading days in a year). The term "continuous" simply means that there are no distortions introduced by the transition from the *current* (expiring) to the *new* first-nearby contract. If X denotes the expiration day for the current first-nearby contract (i.e., the last day it is priced), then on day X we use the percentage change in the *current* first-nearby between days X-1 and X, while on day X+1, we use the percentage change in the *new* first nearby between days X and X+1. In other words, daily percentage changes are always calculated based on like contract months, such that no distortions occur when switching from one contract to the next at expiration. Note that this is different than using the discontinuous price series depicted in Figure 1, which simply switches from the current to the new first nearby contract on day X+1.

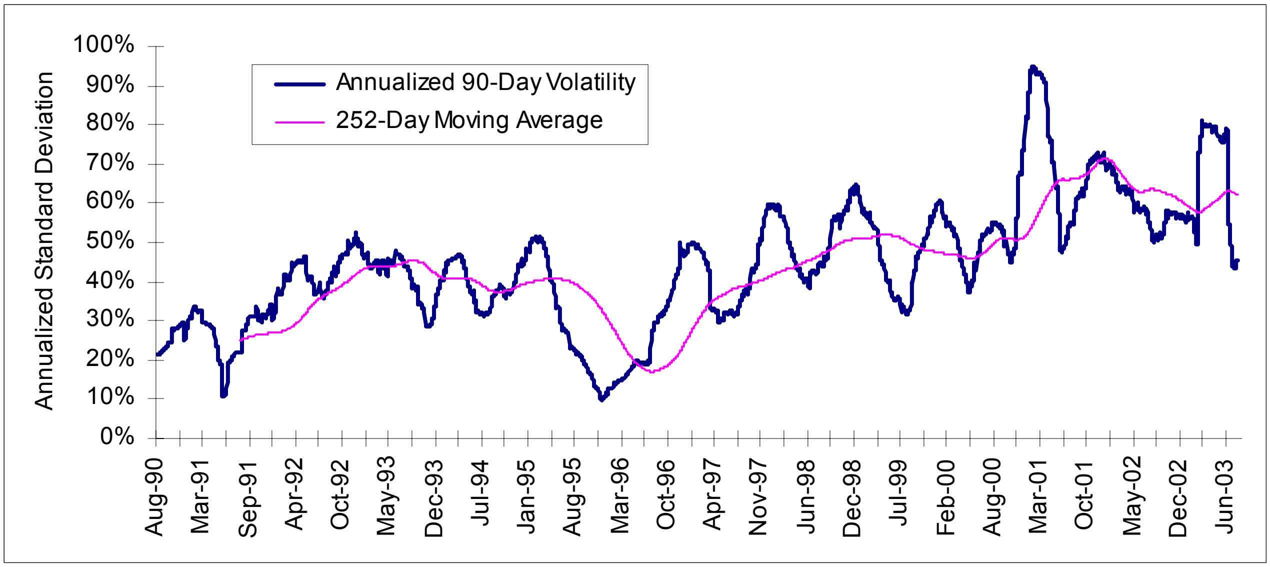

Figure 3. Historical Volatility of Natural Gas Futures Prices

2.2 Implied (Future) Volatility

While gas price volatility is currently near record highs relative to the last 13 years of price history, can one assume that volatility will remain high, or even increase further, in the future? The market itself provides some insight on this matter, through what is known as *implied volatility*. Implied volatility can be loosely defined as the level of volatility that solves the Black-Scholes options pricing formula, given observed options premiums in the market.[9] More simply, implied volatility is the market's forecast of future price volatility.

Figure 4 shows the implied volatility from at-the-money options on third-nearby futures contracts sampled on the first trading day of each month, going back to 1998.[10] While the 12-

[9] As portrayed in Hull (1999), the Black-Scholes formula for the price of a call option on a non-dividend paying stock is $c = S_0 N(d_1) - Xe^{-rT} N(d_2)$ where $d_1 = \frac{\ln(S_0 / X) + (r + \sigma^2 / 2)T}{\sigma\sqrt{T}}$, $d_2 = d_1 - \sigma\sqrt{T}$, S_0 is the stock price at time zero, X is the option strike price, r is the continuously compounded risk-free rate, σ is the volatility (i.e., standard deviation) of the stock, T is the amount of time before the option expires, and $N(x)$ is the cumulative probability distribution function for a variable that is normally distributed with mean = 0 and standard deviation = 1.0. Kahn and Stoft (1993) argue that this Black-Scholes formula can be adapted to commodity options (e.g., natural gas options) simply by substituting the price of the commodity futures contract for the stock price. Volatility, or σ, is the only unknown variable on the right-hand side of the formula; historical volatility is typically calculated and input as a proxy. One can, however, simply observe actual call option prices in the market, and then solve (through an iterative process) for the volatility that is implied by that market price. The result is known as *implied volatility*.

[10] Implied volatility on third-nearby futures represents the market's view of volatility over the coming three months. Our decision to use options on third-nearby (rather than first-nearby) futures reflects a compromise between wanting to derive a long-term estimate of implied volatility yet needing to limit our analysis to portions of the forward curve for which options are still at least somewhat liquid. See Section 3.3 for an explanation of options pricing terminology.

month moving average clearly shifted upwards in the wake of the price spike of 2000/2001, implied volatility currently appears to be reverting to near historically normal levels. While this does not *guarantee* that *actual* volatility will be lower than it currently is going forward, the predictive power of implied volatility has been shown to be superior to that of historical volatility (Szakmary et al. 2002).[11] With gas prices expected to remain above $4.5/MMBtu for the coming six years (according to the futures strip from August 11, 2003), however, even a return to "normal" levels of volatility may still leave more dollars at risk.

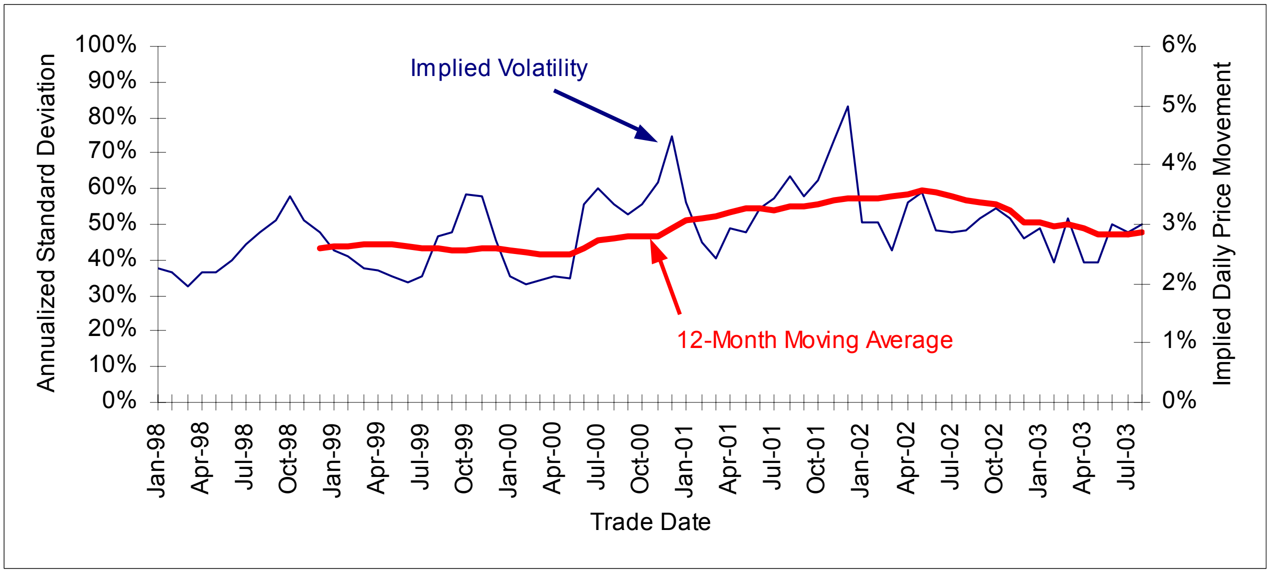

Figure 4. Implied Volatility of Natural Gas Futures Prices

2.3 The Impact of Gas Price Volatility on Electricity Price Volatility

Thus far, we have focused exclusively on natural gas price volatility. Given, however, that the purpose of this paper is to demonstrate and quantify the role that fixed-price renewable electricity generation can play in mitigating fuel price risk, we must know to what extent gas price volatility translates into wholesale electricity price volatility. Figure 5 depicts this relationship: the thick solid line shows the total levelized cost of energy for a hypothetical advanced combined cycle unit over a range of gas prices, while the corresponding thin starred line shows that unit's variable operating costs over the same range.[12] At $4/MMBtu, the cost of natural gas represents *more than half* the total levelized cost of gas-fired generation from an advanced combined cycle turbine, and roughly *90%* of its operating costs. In other words, unless it is hedged, gas price volatility can flow directly into electricity price volatility: at a heat rate of 6,800 Btu/kWh, for each $1/MMBtu increase in gas prices, the levelized cost of generation from state-of-the-art combined cycle units increases by 0.68¢/kWh. For peaking units with higher

[11] In an analysis of 35 different commodities futures markets from 8 different exchanges, Szakmary et al. (2002) found implied volatility (from options on those futures) to be superior to historical volatility at forecasting future volatility in 34 of the 35 markets (natural gas was among the 34).

[12] We include variable operating costs because in a competitive wholesale market with existing gas-fired generation, this is the price against which renewables must compete on the margin.

heat rates, natural gas price spikes translate into even greater electricity price impacts. Moreover, gas-fired plants are often the marginal units that set the market-clearing price for all generators in a competitive wholesale market, allowing natural gas price volatility to have an even greater impact on wholesale electricity price volatility.

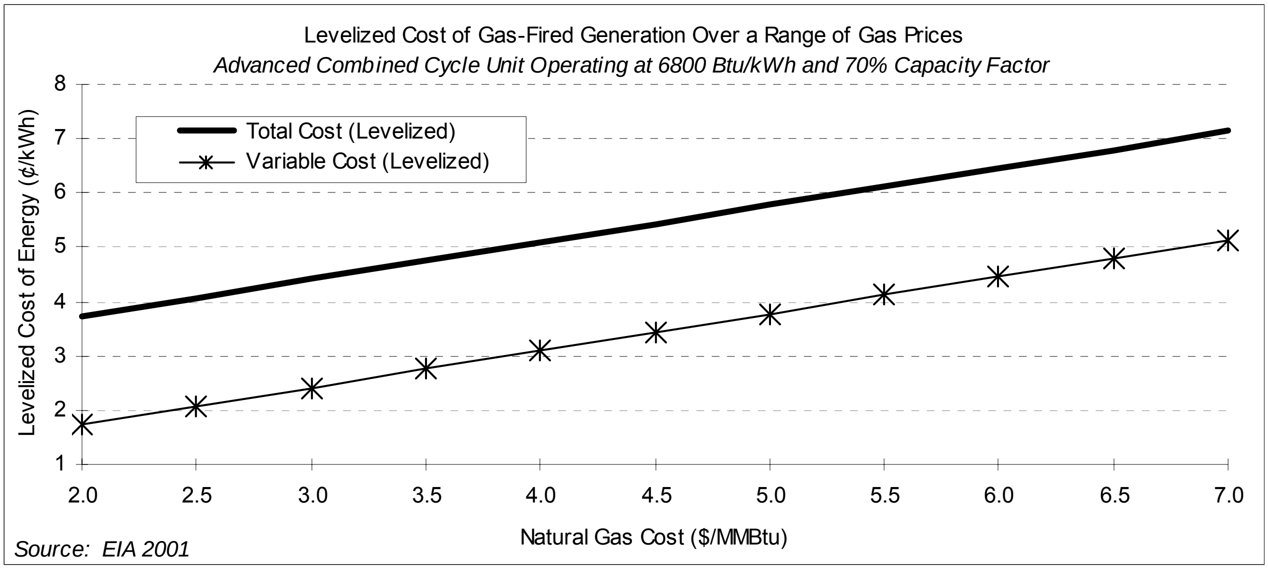

Figure 5. The Cost of Gas-Fired Generation Over a Range of Natural Gas Prices

Clearly, the variability of gas prices poses a major risk to both buyers and sellers of gas-fired generation. The next section provides a brief overview of electricity contract types designed to allocate this risk to either the buyer or seller.

2.4 Electricity Contract Types

Both natural gas-fired and renewable generation can be sold in several different ways. It is important, therefore, to distinguish between the different types of electricity contracts, and how they fit into our analysis.

Electricity can be sold either (1) on the spot market, (2) through contracts that are indexed to (i.e., vary with) the price of the fuel input,[13] (3) through tolling agreements (whereby the power purchaser delivers fuel to the generator and takes delivery of the resulting power that is produced, having effectively "rented" the use of the generation plant), or (4) through fixed-price contracts. Natural gas-fired generation is commonly sold through all four of these contract types (Bachrach et al. 2003), with gas price risk falling on the power purchaser in the first three, and the generator in the final type. Renewable generation, on the other hand, is typically sold through long-term fixed-price contracts (perhaps indexed to inflation), and generally imposes no

[13] Though fuel price indices are most common, electricity contracts may instead be linked to other price indices. For example, an aluminum smelter wishing to stabilize its profit margin may seek an electricity contract that is indexed to the price of aluminum (i.e., the company's output). For the purposes of this paper, we will assume that indexed contracts are linked to the price of the fuel input, natural gas.

gas price risk on either the buyer or seller.[14]

In order to achieve a fuel price risk profile similar to that of fixed-price renewable generation, either the buyer (under spot, indexed, and tolling contracts) or seller (under fixed-price contracts) of gas-fired generation must hedge away natural gas price risk. The next chapter examines different ways to do so, while latter chapters evaluate the cost of such hedges; if this cost systematically differs from the gas prices that are typically used in planning and modeling studies to compare renewable to natural gas-fired generation, then such studies are making an apples-to-oranges comparison with respect to fuel price stability.

[14] We note at least one major exception to this rule: qualifying facility contracts in California have, to some degree, been indexed to natural gas prices. This is the result of historic events, however, that are unlikely to be replicated in the future.

3. Gas-Based Financial and Physical Hedging Instruments

A retail electricity supplier seeking to reduce its natural gas price risk can either invest in renewable generation (which is immune to gas price risk), choose among a number of gas-based financial and physical hedging instruments, or purchase *fixed-price* gas-fired electricity (in which case the *generator* may wish to hedge using financial or physical instruments).[15] Natural gas-based 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.

As shown below in Figure 6, each of these traditional hedging instruments falls into one of two categories: those creating a flat payout pattern that is immune to price movements in either direction (gas futures, swaps, and fixed-price physical supply, as well as fixed-price renewable generation), and those creating a contingent payout pattern that protects against adverse price movements while allowing participation in favorable price movements (gas options and storage). In other words, all of the hedging instruments under consideration can protect gas consumers against a gas price increase, but only options and storage allow the consumer to benefit from a gas price decrease as well. This important distinction will be highlighted in further detail throughout this chapter.

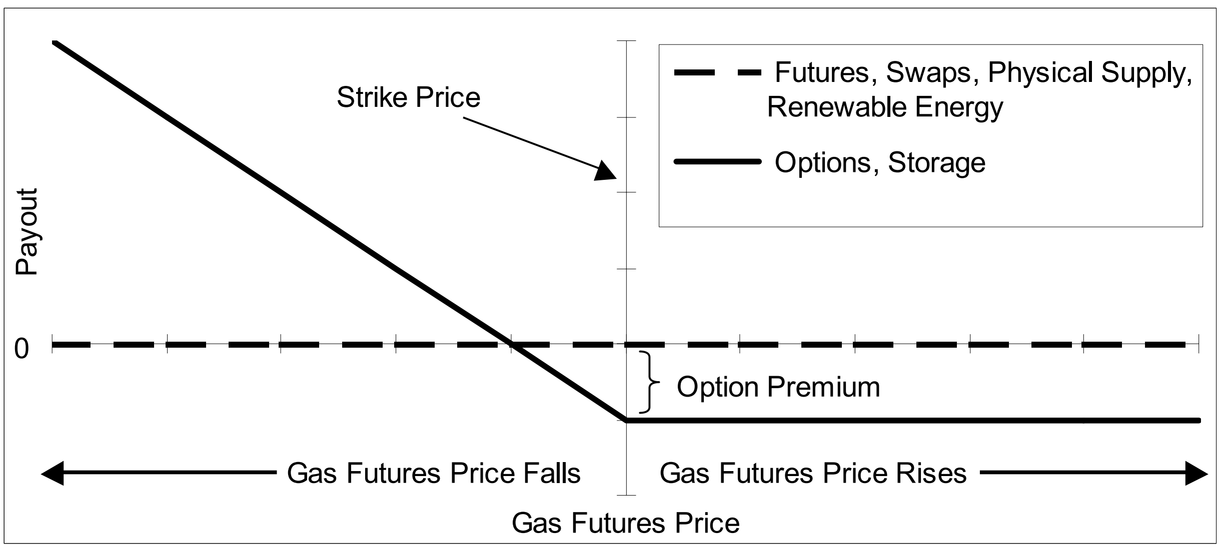

Figure 6. Payout Patterns for Various Hedging Instruments (hedge plus underlying)

Below, we briefly describe each of these gas-based instruments, the specific exposures they hedge, and their costs from the perspective of a gas-fired generator or retail electric supplier exposed to gas price volatility. Our purpose is three-fold: (1) to familiarize the reader with the range of traditional gas-based instruments that can be used to hedge price risk, (2) to determine which of these instruments create a hedged exposure similar to that provided by renewables (i.e., immune to gas price movements in either direction), and (3) to determine the costs associated

[15] Similarly, energy efficiency, or even coal or nuclear power (with fuel costs that are quite stable compared to natural gas), may provide an equivalent natural gas price hedge.

with such instruments.

Readers well-versed in hedging and hedging instruments or otherwise not interested in wading through this material may skip directly to Section 3.6, which distills the most important points from Sections 3.1 through 3.5. Conversely, readers seeking additional detail on derivatives and risk management in the energy industry should see EIA 2002.

3.1 Futures (and Forwards)

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 (though in practice, liquidity dries up relatively quickly beyond the initial 12 months). Each natural gas futures contract is for 10,000 MMBtu to be delivered to 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.[16]

The circled line in Figure 7 depicts the NYMEX natural gas futures "strip" as it closed on November 6, 2001.[17] On that day, the owner of a natural gas turbine (or a retail electric supplier) 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 7. Note that while this transaction removes the risk of paying prices that exceed the current strip over the next 3 years, it also forfeits the potential to benefit from paying lower gas prices should they transpire over this period. Thus, hedging with futures creates a flat and symmetrical payout pattern, as shown above in Figure 6: the hedger is insulated from both price increases *and* decreases.

[16] 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.

[17] Note that Figure 7 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 for now interested in prices from mid-November 2001.

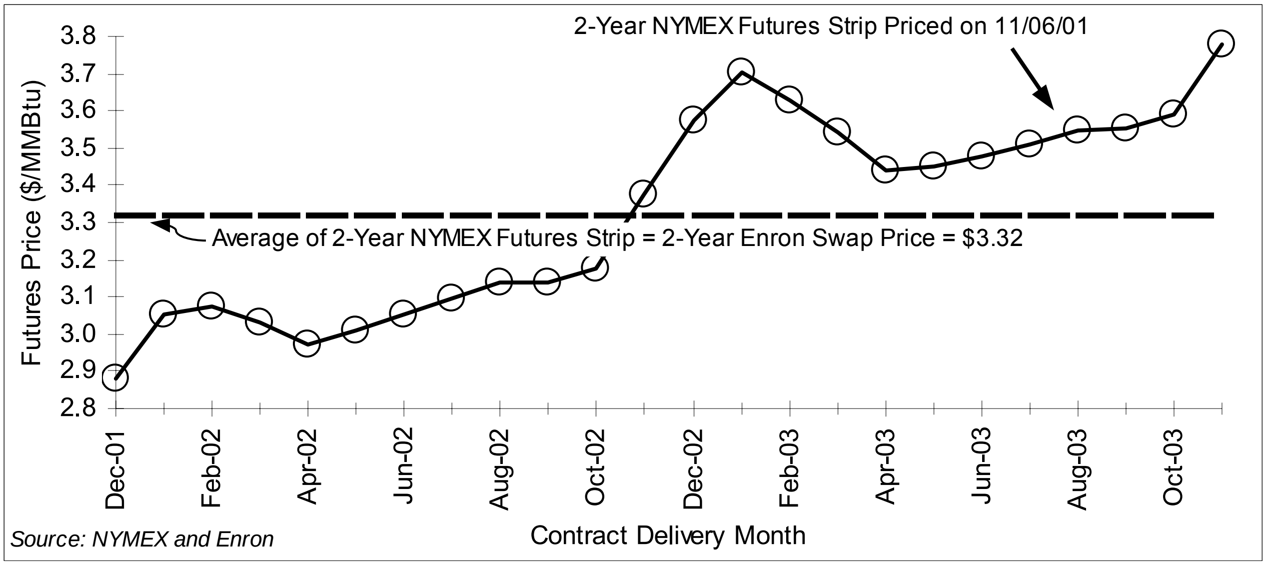

Figure 7. Settlement Price of Natural Gas Futures Strip On 11/06/01

The cost of a futures contract can be thought of as equaling the futures price; unlike with options (discussed below), there is no up-front price premium. In fact, one can establish a futures hedge with very little up-front capital outlay: the hedger will typically only need to pay fees and meet initial and ongoing margin or credit requirements, which amount to a small fraction of the notional contract value. Another advantage of futures contracts is that, because they are exchange-traded and therefore backed by the combined credit of all exchange members, they pose very little credit risk to the buyer and seller (being "marked to market" every day also reduces credit risk).

One disadvantage of hedging with natural gas futures is that contracts are only listed out 72 months (6 years), and are only liquid over the first half of that period, at best (see Figure 25, in Section 6.1.3). Thus, in order to hedge natural gas price risk over the long term (e.g., the natural gas needed to operate a gas turbine over its useful life of 20 years or more) using gas futures, one must adopt a strategy that involves continuously "rolling" the hedge forward, such as a "stack and roll" strategy.[18] Such strategies, however, subject the hedger to price risk with each "roll," particularly if price movements are not uniform along the futures strip. As demonstrated by the massive losses of the German conglomerate *Metallgesellschaft* in 1993, the risks entailed in "stack and roll" and other rolling strategies can be quite substantial.[19]

Forward contracts are essentially the same as futures contracts, with several notable exceptions: forwards are traded between individual counterparties (i.e., not exchange-traded), are highly customizable (in specifications and duration), and are accounted for differently than futures (i.e., gains and losses are realized only at maturity, whereas futures contracts are "marked to market"

[18] Brennan and Crew (1995) discuss various methods of hedging long-maturity liabilities with short-dated futures contracts.

[19] Metallgesellschaft's energy group ran up approximately $1.5 billion in losses, due mainly to cash-flow problems resulting from large forward oil contracts it had written and attempted to hedge using a stack and roll strategy. For more information, see Edwards and Canter (1995).

on a daily basis).[20] Thus, one advantage of forward contracts is that they can be bought and sold for periods longer than the futures strip extends. However, because they are bilateral transactions that are traded "over the counter" (i.e., not on a regulated exchange), forwards will typically be less liquid than futures contracts, and will also entail more credit risk.[21]

3.2 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.

Figure 8 shows a simple schematic of a fixed-for-floating swap. The dashed sinusoidal curve represents the fluctuating spot market (e.g., Henry Hub) price, while the solid flat line at $4/MMBtu represents the fixed swap price over time. Whenever the spot price is above the swap price, the gas consumer (e.g., generator) receives the difference (dark-shaded area). Conversely, whenever the spot price is below the swap price, the gas consumer pays the difference (light-shaded area). In this way, the gas consumer – who continues to purchase the physical gas needed from the spot market – transforms his variable-price liability into a fixed-price liability. Thus, as with futures, hedging with swaps provides a flat, symmetrical payout pattern, as shown earlier in Figure 6.

[20] For an overview of the difference between forward and futures prices, see Section 3.6 of Hull (1999).

[21] While the notion that forwards are less liquid than futures may be true in general, note that in wholesale electricity markets, and even natural gas markets to a lesser extent, the "over-the-counter" market (i.e., where forwards are traded) has historically been much more liquid than exchange-traded futures markets, particularly for deals of any length. One potential explanation for this phenomenon is that futures markets for electricity (and to a lesser extent natural gas) are too rigid and perhaps insufficiently fungible (e.g., given locational basis differentials and transmission constraints) to be useful to customers. For example, an electricity futures contract deliverable to the California-Oregon Border (one of the original NYMEX futures trading hubs) may provide a relatively poor hedge, even to customers in California or Oregon, if there is no way to physically deliver power from the hub to the customer due to a transmission constraint. While relatively few futures contracts actually result in delivery, the *threat* of delivery is paramount to the integrity of the contract as a hedging tool. Perhaps for these reasons, NYMEX was forced by a lack of interest and liquidity to de-list its electricity futures contracts in 2002 (though in April 2003, NYMEX launched a new electricity futures contract deliverable to the PJM western hub).

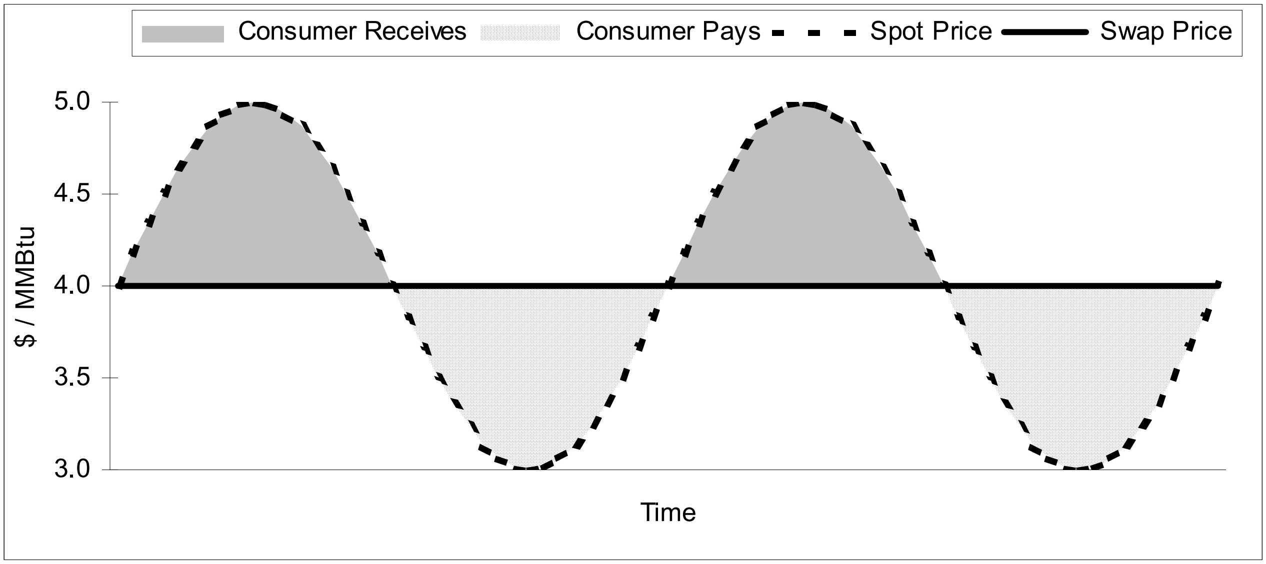

Figure 8. Schematic of a Fixed-for-Floating Swap

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 7 (at a discount rate of 10%) yields a price of $3.32/MMBtu – essentially the same as Enron's swap price (see the flat dashed line in Figure 7).[22]

The cost of hedging with a swap can be thought of as equaling the fixed swap price; again, unlike with options, there is no up-front premium involved. One advantage that swaps have over futures contracts is that swaps – because they are bilateral contracts – can be structured for terms longer than the few years over which futures contracts are liquid. For example, later in this paper we present data on 10-year natural gas swaps; longer terms are possible (though liquidity will decrease as term increases). Of course, because they are bilateral contracts, swaps also tend to be less liquid than exchange-traded futures, and also involve significantly more credit risk, the extent of which depends on the swap counterparties involved in any particular deal.

3.3 Options on Futures

When hedging with futures, forwards, or swaps, a gas-fired generator (or retail electric supplier) 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 retail electric supplier) wants to remove the risk of rising gas prices without relinquishing the ability to capitalize on falling prices, the generator

[22] 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.

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").[23] 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. Thus, the aggregate cost of hedging with options on natural gas futures can be thought of as equaling the strike price (i.e., the cost of the gas futures contract if the option is exercised) plus the options premium.[24]

Figure 9 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 (see Figure 7). 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 had to pay to hedge with options over the entire year – almost \$0.5/MMBtu.[25] In return for this premium, the hedger is not only protected against price increases, but will also benefit from price decreases. In other words, options hedges create asymmetric payout patterns, as shown earlier in Figure 6.

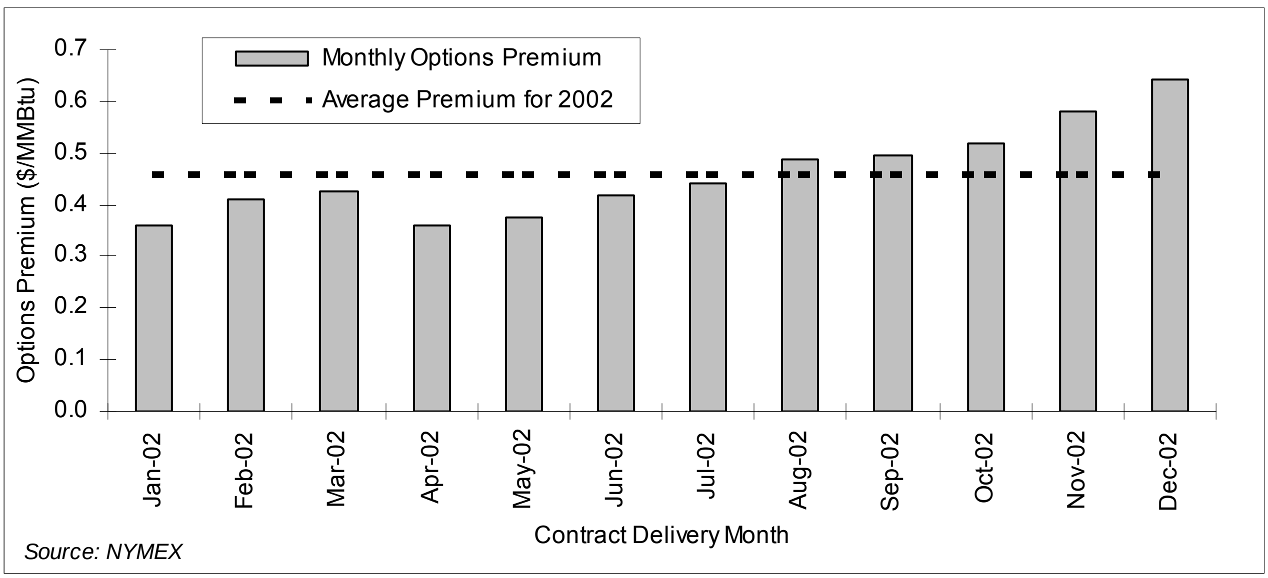

Figure 9. Natural Gas At-The-Money Options Strip On 11/06/01

[23] 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).
[24] In practice, most holders of in-the-money options will likely try to sell their options rather than exercise them, so as to capture any remaining time value, which is forfeited once the option is exercised.
[25] This premium would increase if one attempted to extend the option hedge farther out into the future.

3.4 Fixed-Price Physical Gas Supply

While financial hedges have become increasingly common,[26] fixed-price physical supply contracts for natural gas have historically been the mainstay of gas price risk management. 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,[27] however, financial and physical hedges should – at least theoretically – be priced almost identically.[28] 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.[29] Because of the market discipline imposed by arbitrage and the difficulty in obtaining details on a large sample of actual long-term contracts for physical supply, for the purposes of this paper we simply assume that long-term fixed-price physical supply contracts are economically identical to swaps or futures/forwards of the same duration. Thus, as with swaps, futures and forwards, the cost of hedging with fixed-price physical supply can be thought of as equaling the contract price, and, as shown earlier in Figure 6, fixed-price physical supply also provides a symmetrical payout pattern.

3.5 Physical Gas Storage

Physical storage facilities enable gas to be injected when prices are low (typically in the summer) and withdrawn when prices are high (typically in the winter), 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). Owens (2003a, 2003b) agrees that the cost of storage varies by field, but on average finds costs to be around $0.50/MMBtu, a bit lower than those cited by Xcel. Meanwhile, in a brief filed with the California Public Utilities Commission, Southern California Edison states that its cost of gas storage is closer to $0.36/MMBtu (Isken and Woodruff 2003).

Note that, in general, these costs are fairly close to the explicit cost of hedging with options (i.e., the options premium), discussed earlier, which is perhaps not that surprising (again, due to arbitrage) 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

[26] In the wake of the California electricity crisis, the Enron scandal, and the general credit crunch in the power industry, however, many energy trading firms dealing in financial derivatives have either gone out of business or else have significantly curbed their activities in this area.
[27] 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.
[28] Costello (2001, 2002) notes that financial hedges should be more liquid than physical hedges, and should therefore entail lower transactions costs. This may no longer hold true, given the current state of entrenchment in the energy trading industry.
[29] This arbitrage would not be entirely riskless because credit risk (i.e., risk of default) would undoubtedly remain.

physical option that, like a financial option, creates an asymmetric payout pattern, as shown earlier in Figure 6. And as with financial options, the cost of hedging with storage can be thought of as equaling the cost of the injected gas (i.e., analogous to the strike price), plus the actual cost of storing it (i.e., analogous to the options premium).

3.6 Summary

Of the various forms of hedging discussed above, only options (and the *physical* option of storage) have explicit up-front and easily quantifiable premiums (i.e., explicit costs above and beyond the gas price that is locked in); the cost of all other hedging instruments can be thought of as equaling the price that is locked in.[30] Options, however, tell us little about the "hedge value" of renewable energy,[31] because, as shown earlier in Figure 6, 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. One could combine call and put options in various ways to create synthetic futures, collars, and other more exotic options-based derivatives that would more closely approximate or match the flat, symmetrical payout pattern of renewables. By definition, however, the economics of such instruments can be no better than that of the instrument they are meant to replicate, or the individual components from which they are built.[32] We therefore ignore options and exotic options-based instruments in this paper.

Thus, to fairly evaluate fixed-price renewable and variable-price gas contracts on an apples-to-apples basis (i.e., presuming price stability is valued), we must look to futures, swaps, and fixed-price physical supply contracts, all of which provide a hedged payout pattern similar to that of renewables – i.e., flat and symmetrical, immune to both gas price increases and decreases (see Figure 6, earlier). The next chapter compares the cost of each of these instruments to reference case gas price forecasts from the EIA, with the goal of determining whether resource planning

[30] This definition of "cost" ignores transaction costs, fees, and other ancillary expenses. Furthermore, as the future unfolds, there may be an *opportunity cost* of hedging if, for example, spot gas prices decline but the hedged generator is unable to capitalize on this favorable 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 for us 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 do not address in this report.

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

[32] For example, one can replicate a futures contract by buying an at-the-money call option and selling an at-the-money put option (e.g., see Owens 2003a, 2003b), but doing so would involve paying higher transaction costs than would otherwise be incurred by simply buying the futures contract (e.g., due to two transactions instead of one, as well as less liquidity in general in the options market). One could use a similar strategy to lock in a specific price (rather than the current market price), but again, the profitability of doing so should be no different than simply buying a futures contract, because the option premiums will compensate for any implicit gain or loss assumed with the position (i.e., you would pay to obtain an in-the-money position, and be compensated for obtaining an out-of-the-money position). Finally, one could also use call and put options to establish a "costless" collar around a given price range; while such a position can be implemented cheaply, a collar does not lock in a single price (unless it is a collar of zero width – i.e., a futures contract), but rather a range of prices, which does not completely eliminate risk and is not directly comparable to the hedge that renewable energy offers.

and modeling studies that rely primarily on such forecasts are adequately capturing the price stability benefits that renewable energy provides (which would be the case if forward prices matched price forecasts).

4. Comparing Forward Natural Gas Prices to Long-Term EIA Gas Price Forecasts

Chapter 2 demonstrated that natural gas price volatility poses a major risk within wholesale electricity markets, and that in order to achieve a fuel price risk profile similar to that of fixed-price renewable generation, either the buyer (under spot, indexed, and tolling electricity contracts) or seller (under fixed-price electricity contracts) of gas-fired generation must hedge away natural gas price risk. Chapter 3 concluded that futures, swaps, and fixed-price physical supply contracts are the relevant hedging instruments that provide a symmetrical payout pattern analogous to that provided by renewables. The prices that can be locked in through such contracts are therefore the appropriate (i.e., presuming that price stability is valued) fuel price input to resource acquisition decisions, as well as modeling and planning studies, in which renewable and gas-fired generation are being compared.

As has been noted (and will be demonstrated later in Chapter 5), however, utilities and others conducting such analyses tend to rely primarily on uncertain long-term forecasts of spot natural gas prices, rather than on prices that can be locked in through futures, swap, or fixed-price physical supply contracts (i.e., "forward prices"). This practice raises a critical question: how do the prices contained in uncertain long-term gas price forecasts compare to actual forward prices that can be locked in?

If the two price streams closely match one another, then one might conclude that forecast-based resource acquisition, planning, and modeling exercises are implicitly accounting for the price stability benefits of renewable relative to gas-fired generation, approximating an apples-to-apples comparison. If, however, forward prices systematically differ from long-term price forecasts (e.g., if there is a cost to hedging, or if the forecasts are out of tune with market expectations), then the use of such forecasts in resource acquisition, planning, and modeling exercises will yield results that are biased (again, assuming that long-term price stability is desirable) in favor of either renewable (if forwards < forecasts) or natural gas-fired generation (if forwards > forecasts).

In this chapter, we investigate whether or not forward prices match price forecasts by comparing the prices of futures, swap, and fixed-price physical gas supply contracts to reference case gas price forecasts from the EIA.[33] Chapter 5 will then extend this comparison to other non-EIA forecasts that are also commonly used by utilities and others in resource acquisition, planning,

[33] Again, as noted in Chapter 1, reviewers of a draft of this report from the EIA have characterized their efforts as *projecting* natural gas *costs*, rather than *forecasting* natural gas *prices*. In other words, the EIA reference case assumes that weather and inventory patterns, as well as regulations – all of which can greatly impact market prices – remain "normal" (by historical standards) throughout the forecast period. In this sense, the EIA reference case "forecast" does not necessarily represent the *expected* or *most likely* future market price, and perhaps not even a market price at all. While this subtle distinction will be discussed later in Section 6.2, we note here that we use EIA reference case gas price forecasts in this chapter because they are publicly available, have been widely vetted, and are commonly used by the EIA and others as a "base case" price scenario in policy evaluations and modeling exercises. Furthermore, in Chapter 5 we look at other non-EIA gas price forecasts that may not suffer from this ambiguity.

and modeling exercises, while Chapter 6 will discuss potential reasons why forward prices might differ from price forecasts.

The data necessary to conduct our analysis are deceptively simple: a forward gas price and a gas price forecast, ideally generated at the same time. While long-term gas price forecasts are relatively easy to come by (e.g., the EIA forecasts are publicly available and updated every year), long-term forward prices – and in particular those of sufficient duration to be of interest – present a greater challenge. As noted in Chapter 3, the NYMEX gas futures strip extends out six years (but is liquid for much less than that) – a period that is only about one-third as long as the typical term of a power purchase agreement for renewable energy (which commonly extend 15-25 years). Forward gas contracts in excess of 6 years are traded bilaterally "over the counter" (i.e., not on an organized exchange), and are therefore rarely documented in the public domain. In addition, we must further restrict our already restrictive sample to those forward prices that were traded or posted at roughly the same time as the publication or generation of a long-term gas price forecast (this timing issue will be discussed further in Section 6.3.2).

Thus, despite our best efforts to obtain a larger sample, our analysis is limited to comparisons from the past three Novembers (November 2000-November 2002), and for terms not exceeding 10 years. Specifically, our limited sample of forward contracts and price forecasts includes:

- 2-, 5-, and 10-year natural gas swaps offered by Enron in November 2000 and 2001, compared to reference case natural gas price forecasts from the Energy Information Administration's (EIA) *Annual Energy Outlook 2001* and *2002*, respectively;
- the six-year NYMEX natural gas futures strip from November 2002, compared to the reference case gas price forecast contained in *Annual Energy Outlook 2003*, and;
- a seven-year physical gas supply contract between Williams and the California Department of Water Resources signed in November 2002, again compared to the reference case gas price forecast contained in *Annual Energy Outlook 2003*.

Sections 4.1, 4.2, and 4.3 present the forecast comparisons involving the Enron swaps, NYMEX futures, and Williams physical supply contracts, respectively. Each comparison reveals that forward prices have been trading at a premium to EIA price forecasts; in aggregate, the data show a relatively stable premium in the forward market relative to EIA price forecasts over the last three years.. Section 4.4 evaluates whether the premiums observed in Sections 4.1-4.3 exhibit a conclusive term structure, which might allow us to extrapolate our findings over longer terms. Section 4.5 summarizes the findings of this chapter.

4.1 Enron Swap Contracts (November 2000 and 2001)

Table 1 presents natural gas swap price data extracted from market price reports posted on the now-defunct EnronOnline, and shows that on November 6, 2001, for example, a gas-fired generator or retail electric provider could have locked in a fixed gas price of \$3.876/MMBtu at the Henry Hub 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.[34] 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**	
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)

We evaluate these swap prices against 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 the *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 first-nearby NYMEX futures prices (which are indexed to Henry Hub) to delivered (to electricity generators) prices on a monthly basis from April 1990 through December 2002 (n=153 months).[35] This comparison revealed an average transportation margin of $0.38/MMBtu, with a 95% confidence interval that ranges from $0.33 to $0.43/MMBtu. To account for this transportation margin, each year we subtracted $0.38/MMBtu from the EIA forecast of prices delivered to electricity generators.

Figures 10 and 11 show the resulting forecasts 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).[36]

[34] Unfortunately, Enron slipped into bankruptcy soon after we began collecting this data, greatly hindering our efforts to obtain a larger sample size. Section 6.3 will discuss the relevant question of whether the limited swap price data we were able to collect are even usable, or perhaps distorted by manipulative behavior and/or extenuating circumstances.

[35] Because of their relatively short time to expiration (< 1 month), first nearby futures prices (sometimes referred to as "spot month" prices) are a close approximation of spot prices.

[36] Unless otherwise noted, throughout this report all forecasts are expressed in *nominal* (as opposed to *real* or constant dollar) terms in order to be comparable to forward prices, which are also expressed in nominal terms. For example, we inflate the AEO gas price forecasts – which are expressed in real terms – to nominal terms using the EIA's own inflation projections.

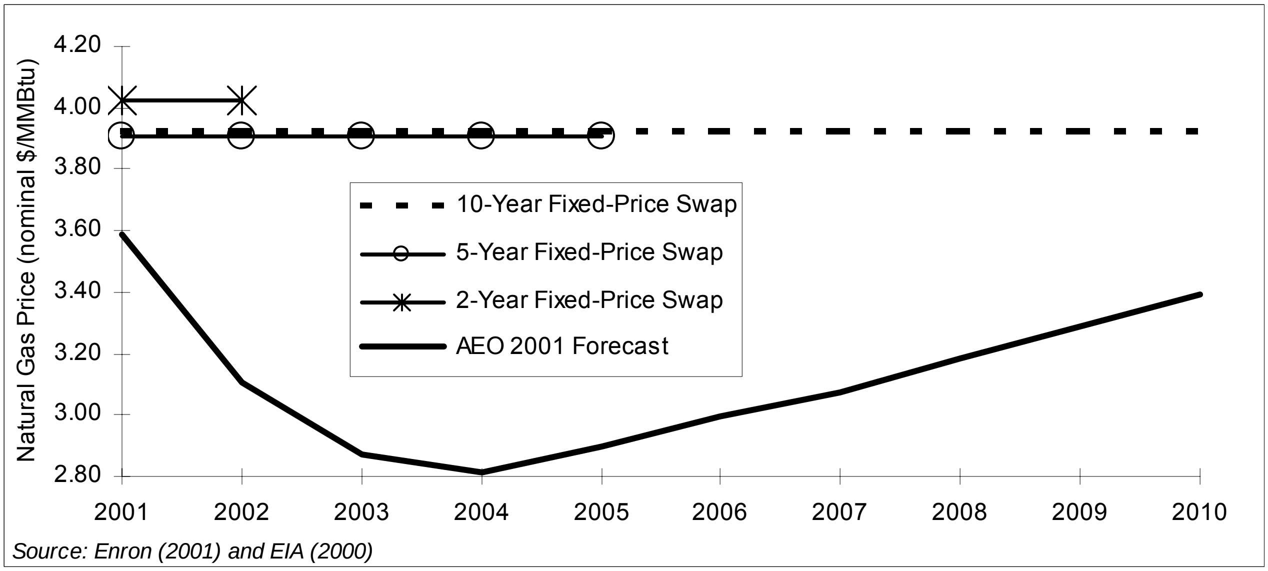

Figure 10. November 2000 Swap Prices vs. AEO 2001 Natural Gas Price Forecast

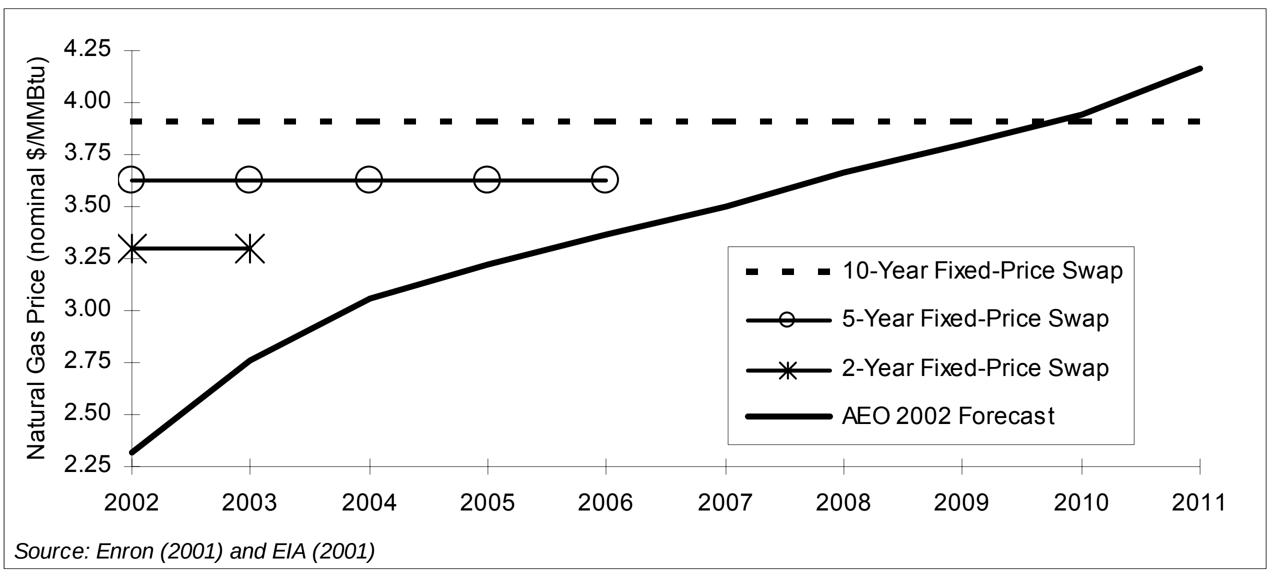

Figure 11. November 2001 Swap Prices vs. AEO 2002 Natural Gas Price Forecast

Figures 10 and 11 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 had to pay a premium to lock in gas prices through a swap, at least relative to the long-term EIA forecast of spot natural gas prices in November 2000 and 2001.[37] Table 2 presents these premiums for

[37] Note that the fact that the swap prices are fixed over time while the EIA forecast is variable does not automatically imply that there is a term structure to the implied premium (though there may well be), but rather reflects the reality of how swaps are quoted – on a fixed-price basis over the contract period. To determine the term structure of the premium (i.e., how the premium varies over time), one would have to know the shape of the forward curve that was used to price the swap. That is, the swap can be thought of as the levelized equivalent of some forward price curve, the shape of which is needed to determine the term structure of the premium. While we are not privy to Enron's

November 2000 and 2001 (in parentheses, respectively), as well as the average of the two years (in bold).[38] The first column lists the premium in natural gas terms ($/MMBtu), while the second and third columns translate the premium into electricity terms (¢/kWh) at heat rates of 7,000 and 10,000 Btu/kWh, representing state-of-the-art and "average fleet" efficiency, respectively.

Table 2. Implied Premiums (Enron Swap Offer – Levelized EIA Gas Forecast)

	Average Premium (November 2000, November 2001)		
Term	**$/MMBtu**	**¢/kWh** *(7,000 Btu/kWh)*	**¢/kWh** *(10,000 Btu/kWh)*
2-Year	**0.72** (0.67, 0.78)	**0.50** (0.47, 0.54)	**0.72** (0.67, 0.78)
5-Year	**0.77** (0.82, 0.73)	**0.54** (0.57, 0.51)	**0.77** (0.82, 0.73)
10-Year	**0.74** (0.81, 0.68)	**0.52** (0.56, 0.47)	**0.74** (0.81, 0.68)

Because investments in renewable energy are typically long-term, the 10-year premiums are of most interest to our analysis. As shown, the 10-year premiums of $0.81/MMBtu and $0.68/MMBtu in November 2000 and 2001, respectively, average to $0.74/MMBtu. Translated into ¢/kWh using an aggressive heat rate of 7,000 Btu/kWh, this premium equates to 0.52¢/kWh that one would have had to pay (above and beyond the EIA long-term reference case forecast of spot natural gas prices) to hedge the natural gas price risk embedded in wholesale electricity prices (at 10,000 Btu/kWh, the premium rises to 0.74¢/kWh).

4.2 NYMEX Futures Contracts (November 2002)

The bankruptcy of Enron in late 2001 and the subsequent "shakedown" of trading desks at natural gas and power companies across the country had a significant impact on our ability to extend our analysis to November 2002, when the EIA released the *Annual Energy Outlook 2003* and its accompanying long-term gas price forecasts. On the downside, prices of long-term natural gas swaps were no longer publicly available from Enron (which was in liquidation) or any other gas trader.[39] On the upside, the NYMEX – moving swiftly to fill the void left by the implosion of gas trading desks across the country – extended its natural gas futures strip out an additional 36 months, to 72 months (i.e., 6 years) total. Thus, the extent of our November 2002 comparison is limited to 6 years instead of 10.[40]

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forward price curve, we approximate portions of it in Section 4.4 by making use of the information implicit in the 2-, 5-, and 10-year swap prices.

[38] We derived the premiums by levelizing the first 2, 5, and 10 years of the EIA forecasts (using a discount rate of 10%) and subtracting the resulting levelized forecast price from the corresponding averaged swap prices.

[39] Note that in addition to the usual concerns over the proprietary nature of forward price data, gas traders are currently particularly sensitive about disclosing any prices to the public, given ongoing allegations of price manipulation and several high-profile arrests of gas traders who are alleged to have deliberately reported misleading prices to trade publications.

[40] Although the NYMEX posts settlement prices for the entire 6-year strip, liquidity is quite limited beyond the first year or so, and some of the contracts in the sixth year of the strip have never traded (i.e., there is no open interest). The NYMEX has a somewhat involved procedure for calculating settlement prices for such illiquid contracts that involves considering the spread relationships between the contract in question and more actively traded contracts. While this approach may be methodologically sound, it is nonetheless worth noting that in the absence of actual trades (or at least strong bids and offers) it may not be possible to execute a trade in long-dated gas futures at or near the NYMEX settlement price.

Using the same methodology and adjustments to the EIA forecast described above,[41] Figure 12 shows that, just as in November 2000 and 2001, futures prices – which, just like a swap, can be locked in to create price certainty – appear to have been trading at a premium to the EIA's reference case forecast of spot natural gas prices in November 2002.[42]

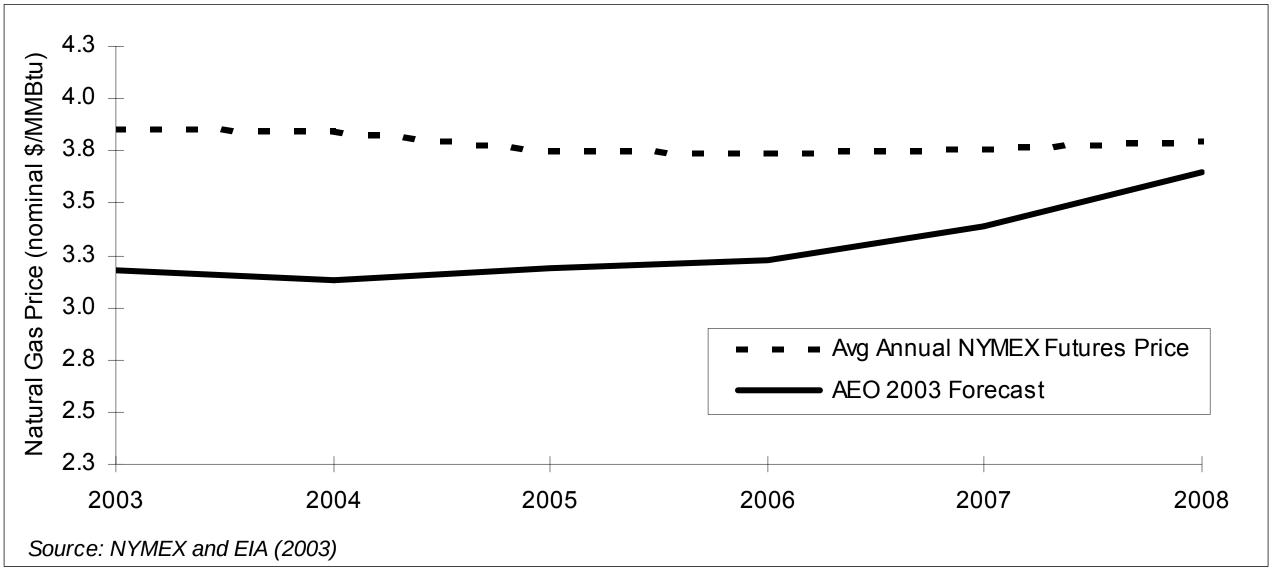

Figure 12. November 4, 2002 NYMEX Prices vs. AEO 2003 Natural Gas Price Forecast

Table 3, which includes the 2- and 5-year terms (rather than just the full 6-year term) for the sake of comparison to the Enron swaps presented earlier in Table 2, shows that the magnitude of the premium is a bit lower than, though not entirely inconsistent with, those observed in the two previous years (and listed in Table 2).

[41] Since NYMEX gas futures prices are listed monthly, we averaged the monthly prices each year to arrive at an annual price that can be compared to the annual EIA gas price forecast. Note that each annual price in the EIA forecast represents a volume-weighted average of peak (December-March) and off-peak (April-November) seasonal prices, which implies that our average of NYMEX prices should also be volume-weighted. We have not done so here, however, because: (1) we do not know the weights that the EIA gives to the peak and off-peak periods; (2) we are unable to similarly volume-weight the Enron swap prices presented earlier; and (3) volume-weighting based on an assumption of 50% more volume in off-peak than on-peak periods (remember that these are prices delivered to electricity generators, which likely see the highest demand in the summer months) only reduces the average annual price by about $0.02/MMBtu, a difference that is hardly perceptible.

[42] We chose November 4, 2002 to sample the NYMEX settlement prices because the AEO 2003 gas price forecast was finalized the very next day (November 5, 2002), meaning that the latest market information available to the EIA was from November 4. See Section 6.3.2 for a discussion of the importance of coordinating the timing of the price sample and forecast.

Table 3. Implied Premiums (Levelized NYMEX Prices – Levelized EIA Gas Forecast)

Term	Premium		
	$/MMBtu	**¢/kWh** *(7,000 Btu/kWh)*	**¢/kWh** *(10,000 Btu/kWh)*
2-Year	**0.69**	**0.49**	**0.69**
5-Year	**0.58**	**0.41**	**0.58**
6-Year	**0.53**	**0.37**	**0.53**

4.3 Williams Physical Gas Supply Contract (November 2002)

Also in November 2002, California's Department of Water Resources (DWR) and the Williams Company announced that they had successfully renegotiated a long-term power purchase agreement for gas-fired generation that the DWR had originally signed with Williams in February of the previous year.[43] The renegotiated contract included a long-term natural gas supply deal for years 2004 through 2010. Specifically, Williams agreed to supply a fixed amount of natural gas each month (though varying seasonally) to the Southern California Border, at the fixed annual prices shown in Figure 13 (CDWR 2002).

The gas supply deal was signed on November 11, 2002 – only six days after the *Annual Energy Outlook 2003* long-term gas price forecasts were finalized on November 5. To translate this forecast into Southern California Border terms, we subtracted $0.38/MMBtu as described above to get to Henry Hub terms, and then added back $0.21/MMBtu to account for the historically positive basis between the Southern California Border and Henry Hub.[44]

[43] For more information on the long-term electricity contracts signed by the DWR, along with analysis of the specific risks they entail, see Bachrach et al. (2003).

[44] The $0.21/MMBtu basis estimate comes from Appendix D of NWPPC (2002), and is derived from historical basis differentials. Note that the comparison of the Williams contract to the EIA forecast rests on the assumption that the seasonal volume-weighting implicit in the EIA's annual price delivered to electricity generators matches the seasonal delivery profile of the Williams contract (1.8 trillion Btu/month from May through October, and 1.2 trillion Btu/month from November through April, all at the same price each year). Given that Williams will deliver 50% more gas in the summer than in the winter – a pattern that one might expect to see repeated in gas-fired generators nationwide – this assumption appears to be reasonable.

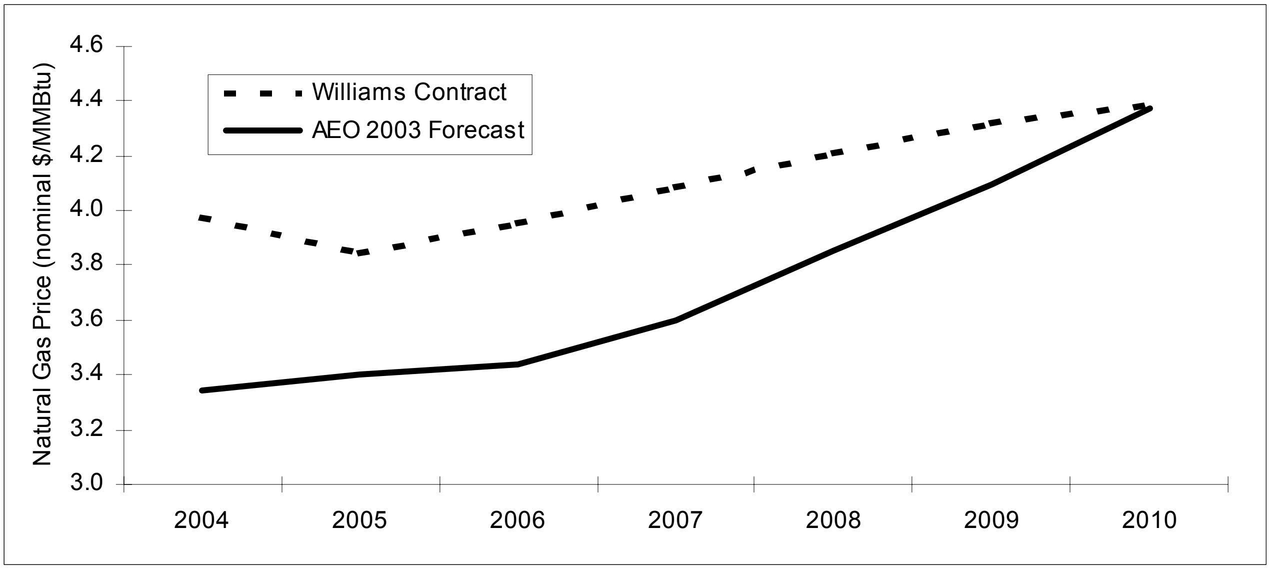

Figure 13. Williams Contract vs. AEO 2003 Gas Price Forecast

As shown in Figure 13, the Williams gas contract is also priced at a premium to the basis-adjusted EIA forecast. Table 4 shows the 2-, 5-, 6-, and 7-year premiums (again, we present all of the different terms, rather than just the full 7-year term, for the sake of comparison to the Enron and NYMEX contracts presented earlier). Note that the premiums are of similar magnitude to those shown above in Table 3, suggesting that the Williams contract prices are roughly in line with NYMEX futures prices.

Table 4. Implied Premiums (Levelized Williams Contract – Levelized EIA Forecast)

	Premium		
Term	**$/MMBtu**	**¢/kWh** *(7,000 Btu/kWh)*	**¢/kWh** *(10,000 Btu/kWh)*
2-Year	**0.55**	**0.38**	**0.55**
5-Year	**0.50**	**0.35**	**0.50**
6-Year	**0.47**	**0.33**	**0.47**
7-Year	**0.42**	**0.29**	**0.42**

4.4 The Term Structure of Observed Premiums

Figure 14 consolidates the premiums (in terms of $/MMBtu and ¢/kWh, assuming a heat rate of 7,000 Btu/kWh) from Tables 2, 3, and 4 into a single graph. While it is perhaps not surprising that the premiums vary somewhat from year to year, contract to contract, and by contract term, the fact that in 3 of the 4 contracts the premium appears to be *declining* as the contract term increases is a bit surprising, and raises the issue of *term structure* – i.e., how the premiums vary with contract term. If there is a consistent and predictable term structure to the premiums we have observed, then it might enable us to extrapolate our findings over longer contract terms than those we have been able to collect to date. In other words, our historical forward natural gas price data extends a maximum of 10 years into the future, while today only six years of forward price data is readily available (from the NYMEX), but renewable energy contracts commonly provide price stability for periods of 15-25 years. Knowing a bit about the term structure of the premiums might enable us to extrapolate our findings over longer periods that are more consistent with the duration of renewable energy contracts.

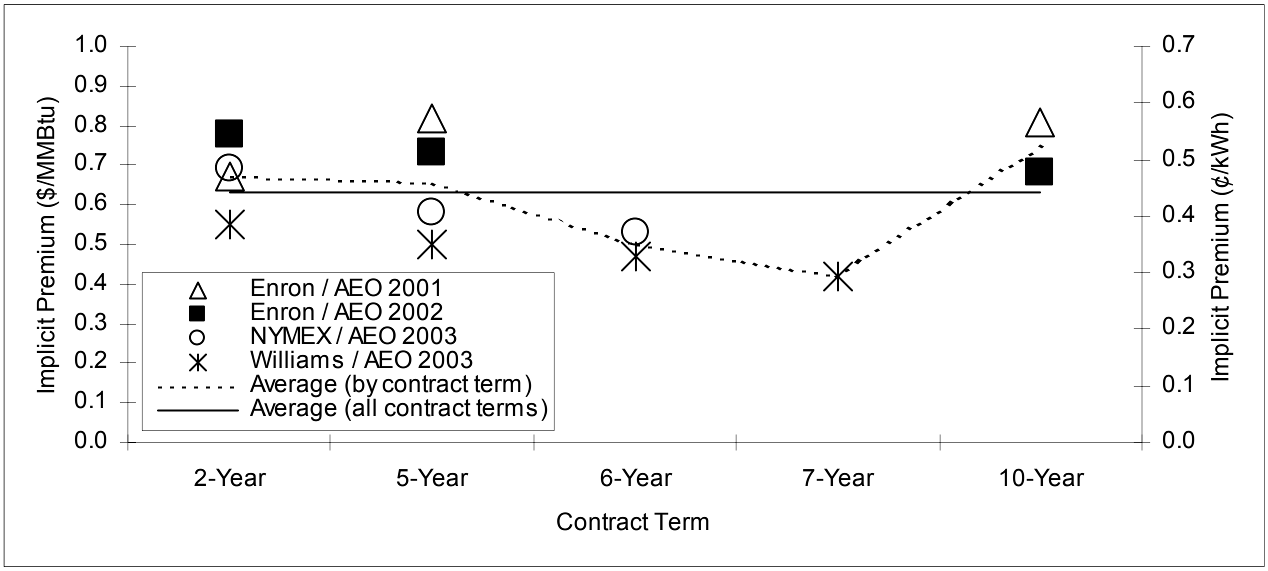

Figure 14. Composite Premiums in $/MMBtu and ¢/kWh (assuming 7,000 Btu/kWh)

Unfortunately, the data are inconclusive. While it is clear that the NYMEX and Williams comparisons exhibit an inverted term structure (i.e., premiums declining with time),[45] the Enron data are not as conclusive, though it is hard to say for certain given the "blocky" nature of the Enron swap data (i.e., levelized over multiple years).

Recall from Table 1 and Figures 10 and 11 that we collected 2-, 5-, and 10-year Enron swap prices from early November 2000 and 2001. Knowing the 2- and 5-year swap prices, one can back into the implied 3-year swap price for years 3-5 of the 5-year swap. Similarly, knowing the 5- and 10-year swap prices, one can back into the implied 5-year swap price for years 6-10 of the 10-year swap. Pulling the relevant pieces together, one can assemble a composite 10-year "forward swap curve" with somewhat of a term structure. Figures 15 and 16 show these implied curves from November 2000 and 2001, plotted against the corresponding AEO gas price forecast. The bars (right scale) represent the difference between the two (i.e., the premium).

[45] Perhaps in support of an inverted term structure is the fact that short-dated forwards are more volatile than long-dated forwards, because price shocks tend to moderate over time as both supply and demand have time to adjust (Graves 2002). Alternatively, it could simply be the case that the long-term EIA forecasts have been particularly out of step with the short-term price increases of the past few years, but that over longer terms the two begin to converge more closely.

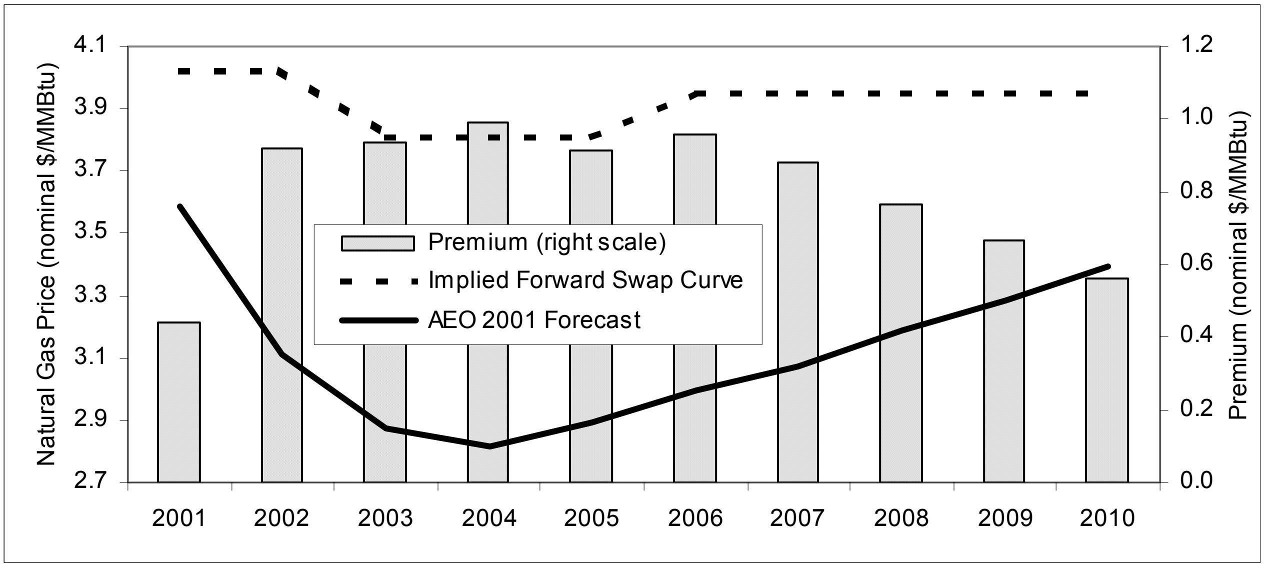

Figure 15. Implied November 2000 Enron Forward Swap Curve vs. AEO 2001 Price Forecast

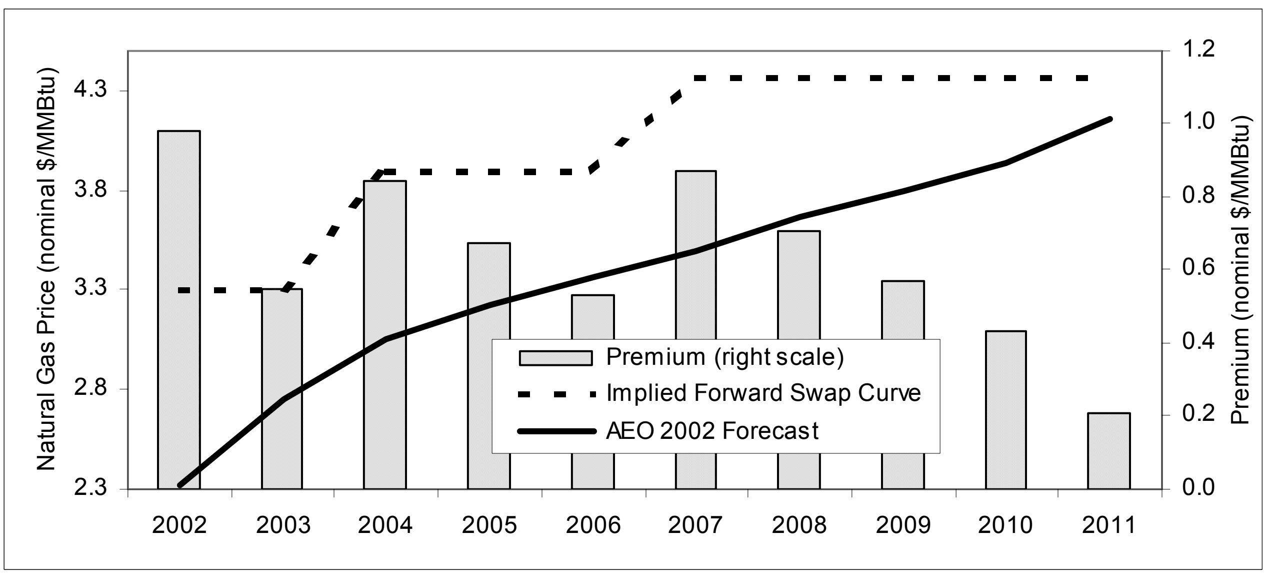

Figure 16. Implied November 2001 Enron Forward Swap Curve vs. AEO 2002 Price Forecast

As shown in both figures, premiums for the first six years exhibit no discernible term structure. Years 7-10 in both figures do exhibit an inverted term structure (i.e., premium declining steadily over time), but this is most likely a result of our inability to calculate anything other than a single averaged forward price for years 6-10, due to limitations in the terms of the original swap data (i.e., we have no swap terms between 5 and 10 years with which to refine the curve in years 6-10). With the effective forward price held artificially constant over this period while the forecast increases steadily, it is hardly illuminating that the implied premiums decline over time. Furthermore, it makes little sense that an inverted term structure would only manifest itself starting in the sixth year of a ten-year swap, perhaps allowing us to tentatively conclude that the Enron swap prices do not support the idea of premiums that exhibit an inverted term structure.

With half of our contract sample (NYMEX and Williams contracts) yielding implied premiums that exhibit an inverted term structure, while the other half (both Enron swaps) does not, it is not possible for us to draw any definitive conclusions on this matter. Thus, we are unable to extrapolate the premiums derived in Sections 4.1-4.3 to contract terms longer than those measured (i.e., 2-10 years).

4.5 Summary

Comparing natural gas forward prices and EIA reference case price forecasts from November 2000, 2001, and 2002 reveals that forward prices have traded above EIA price forecasts during this three-year period, sometimes significantly so. As shown in Figure 14 above, the magnitude of the empirically derived premiums varies from year to year, contract to contract, and by contract term, ranging from \$0.4-\$0.8/MMBtu (\$0.6/MMBtu on average), or 0.3-0.6¢/kWh (0.4¢/kWh on average) assuming a highly-efficient gas-fired power plant.[46]

While one cannot easily extrapolate these findings beyond the last three Novembers, or to contract terms longer than those examined, it is at least apparent that utilities and others who have conducted resource planning and modeling studies based on EIA reference case gas price forecasts over the past three years have produced “biased” results (i.e., presuming that long-term price stability is valued) that favor variable-price gas-fired over fixed-price renewable generation, potentially to the tune of ~0.5¢/kWh on a levelized basis. The next chapter examines other, non-EIA, long-term gas price forecasts to determine whether our findings of empirical premiums are specific to the EIA reference case forecasts.

[46] We emphasize that these premiums are benchmarked to EIA reference case gas price forecasts, and that the magnitude – and perhaps even the sign – of the premiums will change if our sample of forward prices is compared to price forecasts that differ from the EIA reference case. Chapter 5 will present several non-EIA forecasts and calculate the impact on the premium of using such forecasts instead of EIA forecasts.

5. Survey of Other Long-Term Gas Price Forecasts

All of the comparisons that we made in Chapter 4 used EIA reference case gas price forecasts from the *Annual Energy Outlook* (AEO). This is a reasonable starting point, given that EIA forecasts are publicly available, highly documented, and widely reviewed and used (even by utilities) in modeling exercises and resource planning processes throughout the country. The EIA's forecasts, however, are by no means the only long-term gas price forecasts available to market participants. Among others, PIRA Energy Group, DRI-WEFA, and Energy and Environmental Analysis (EEA) all provide proprietary long-term gas price forecasts to utilities and others.

Obviously, unless these other forecasts are in close agreement with EIA reference case forecasts, the spread between them and forward prices will be different from that measured in Chapter 4 (i.e., using EIA reference case forecasts). The purpose of this chapter is to compare the EIA forecasts used in Chapter 4 to these other available forecasts, in order to assess how the observed premiums would change had we compared forward prices to some forecast other than the EIA's. We begin with comparisons of the AEO forecast to other gas-price forecasts, as presented in the AEO itself, and then turn to an evaluation of recent utility Integrated Resource Plan documents.

5.1 AEO Forecast Comparisons

Each year in the AEO, the EIA compares its reference case natural gas price forecast to a number of different private sector forecasts for certain years (e.g., 2015 and 2020). Figure 17 shows the forecast comparison for the year 2015 from the past eight AEOs, while Figure 18 shows the forecast comparison for 2020 from the past six AEOs.

While the private sector forecasts are typically generated earlier in the year than the EIA forecast and therefore may not be strictly comparable,[47] Figures 17 and 18 reveal that the EIA forecast (depicted by the shaded circles) has consistently been at the upper end of the forecast range.[48] This suggests that the forward-forecast premium identified in Chapter 4 as ranging from \$0.4-\$0.8/MMBtu when benchmarked against the EIA reference case forecast would actually be higher – sometimes considerably so – if benchmarked against other widely used gas price forecasts.

[47] Given that these are *long-term* forecasts, this difference of a few months may not be much of a concern. However, since there is a generally rising trend exhibited in Figures 17 and 18, we also decided to conservatively lag the EIA forecasts by a year (e.g., compare the EIA forecast from AEO-02 to the forecasts contained in the *Forecast Comparisons* section of AEO-03) to see what impact that would have on our conclusions. While the lagged figures (which are not shown here, but can be envisioned by mentally shifting the shaded dots in Figures 17 and 18 one year to the right) are not as convincing, they still tell the same basic story: that the EIA natural gas price forecasts are generally higher than those developed by other organizations.

[48] The EIA cautions not to make too much of these differences, given that they are single-year point estimates that do not capture the cyclical nature of some of the other forecasts. For example, note how the EEA forecast is above the AEO2003 forecast in 2015, but below the AEO2003 forecast in 2020 – this could reflect a cyclical swing in the EEA forecast.

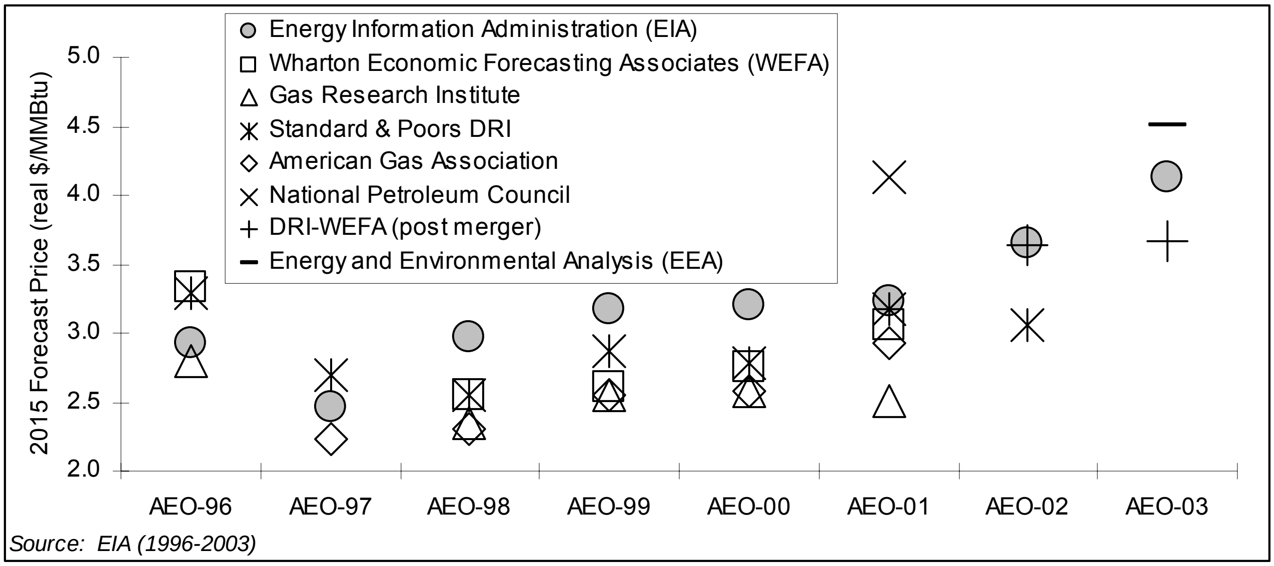

Figure 17. AEO Forecast Comparisons for 2015

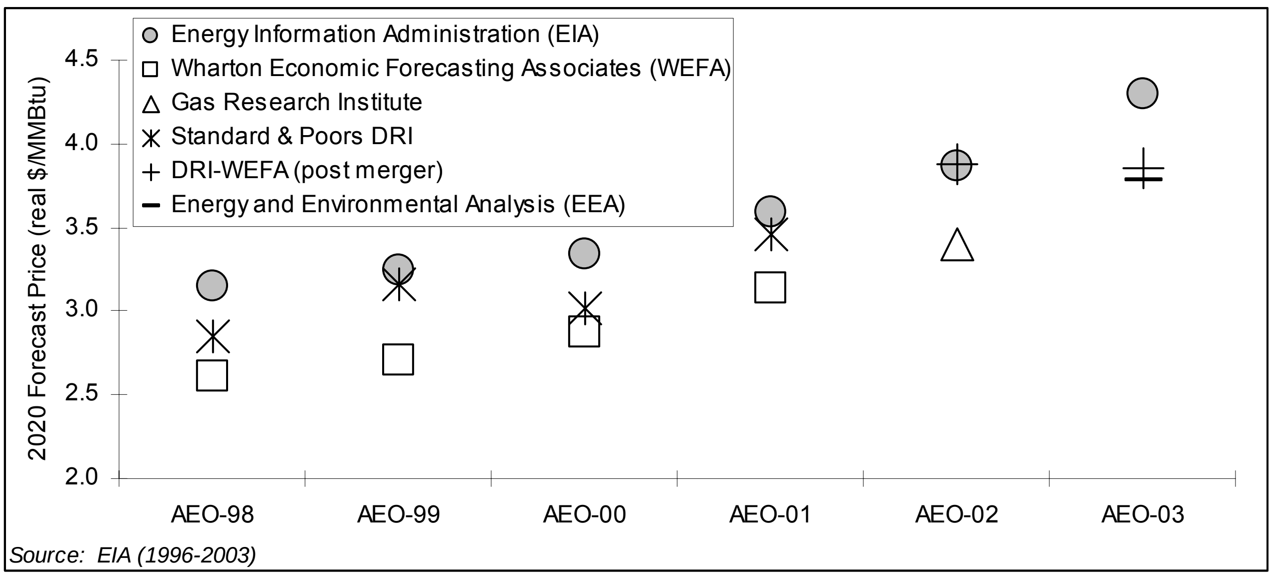

Figure 18. AEO Forecast Comparisons for 2020

5.2 Utility Integrated Resource Plans

An examination of recent utility integrated resource plans reveals other forecast data, as well as useful information about which forecasts market participants are using.

- **Idaho Power's** 2002 resource plan uses actual natural gas forward prices for 2002, and a November 2001 WEFA forecast of prices delivered to electricity generators in the Mountain region for 2003-2011 (Idaho Power 2002). Figures 17 and 18 (above) show that WEFA (and DRI-WEFA) forecasts have historically been lower than EIA reference case forecasts (at least for 2015 and 2020); Figure 19 (below) supports this notion.

- **Avista Energy's** 2003 resource plan uses forward market prices for the first 5 years, and then reverts to a long-term gas price forecast from DRI-WEFA (Avista 2003).
- **Portland General Electric's (PGE)** 2002 resource plan uses actual forward prices for 2003 and 2004, and then linearly interpolates between those forward prices and the EIA's reference case forecast (from *Annual Energy Outlook 2002*) in 2005. From 2006 on, PGE relies solely on the EIA reference case forecast (PGE 2002). PGE's previous resource plan (PGE 2000) notes that the utility chose the EIA forecast over one by Cambridge Energy Research Associates (CERA) for two reasons: (1) the EIA forecast and its documentation are in the public domain and have therefore been more widely reviewed and scrutinized than the CERA forecast, and (2) the CERA forecast contained more cyclical variation, which PGE contends can lead to timing errors in some instances (PGE 2000).
- **Pacificorp's** 2003 resource plan blends actual forward prices with a long-term fundamental forecast from PIRA Energy Group as follows: it uses forward prices exclusively through June 2005, then slowly phases into the PIRA March 2002 forecast over the next 18 months (Pacificorp 2003). From 2007 onward, Pacificorp relies solely on the PIRA forecast, which falls below the EIA reference case forecast starting in 2009 (see Figure 20 below).
- **Puget Sound Energy's** 2003 resource plan also relies on a long-term PIRA forecast from January 17, 2003, with actual forward market prices substituted for 2003 and 2004 (see Figure 21 below) (Puget Sound Energy 2003).
- **Xcel Energy's** 2002 resource plan for Minnesota is based on a natural gas forecast that is also derived from a PIRA Energy Group forecast, this time from October 2002 (Paulson 2002). It is unclear whether or not Xcel adjusts the PIRA forecast in the early years to reflect actual forward market prices.

The resource plans of Idaho Power, Pacificorp, and Puget Sound Energy present new forecast data worth examining. Starting with Idaho Power, Figure 19 plots Idaho Power's natural gas forecast for electricity generators in the Mountain region against the EIA's reference case forecast of the same, taken from AEO 2002 (instead of AEO 2003) to better match the November 2001 date of the WEFA forecast used by Idaho Power. As shown, Idaho Power's forecast is consistently below the EIA's; the difference between the two (on a levelized basis over 10 years) is $0.61/MMBtu. Had we compared the 10-year Enron swap from November 2001 to this WEFA-based forecast rather than to the AEO 2002 reference case forecast, we would have observed a 10-year levelized premium of *$1.29/MMBtu* (instead of $0.68/MMBtu), which translates to 0.9¢/kWh at an aggressive heat rate of 7,000 Btu/kWh.

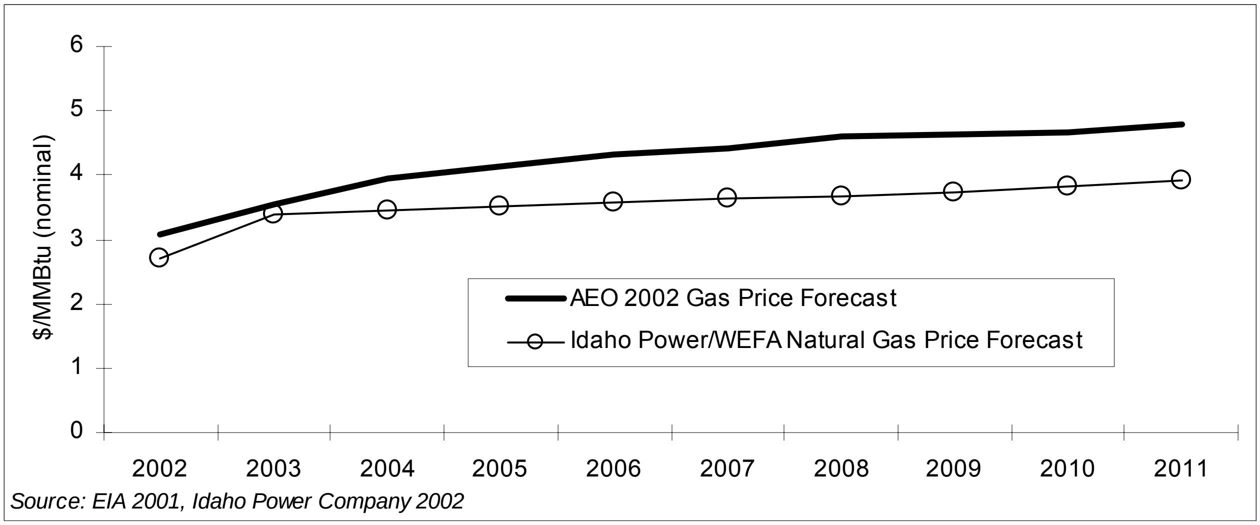

Figure 19. Idaho Power Gas Price Forecast vs. AEO 2002 Forecast

Figure 20 plots Pacificorp's natural gas price forecast (for Utah) against the AEO 2003 reference case forecast (delivered to electricity generators).[49] As shown, Pacificorp's forecast slightly exceeds the AEO forecast through 2008, and then falls well below the AEO forecast from 2010 onward. Since the Pacificorp forecast is based at least in part on actual forward prices through 2006, it is not surprising that the early years of Pacificorp's forecast exceed the AEO reference case forecast. In fact, we would be more alarmed if it did not, given our findings that forward prices for natural gas have traded above long-term forecasts of future spot prices for the past three years. Nonetheless, over the full 20-year period, the Pacificorp gas price forecast averages (on a levelized basis) $0.30/MMBtu lower than the EIA reference case forecast.

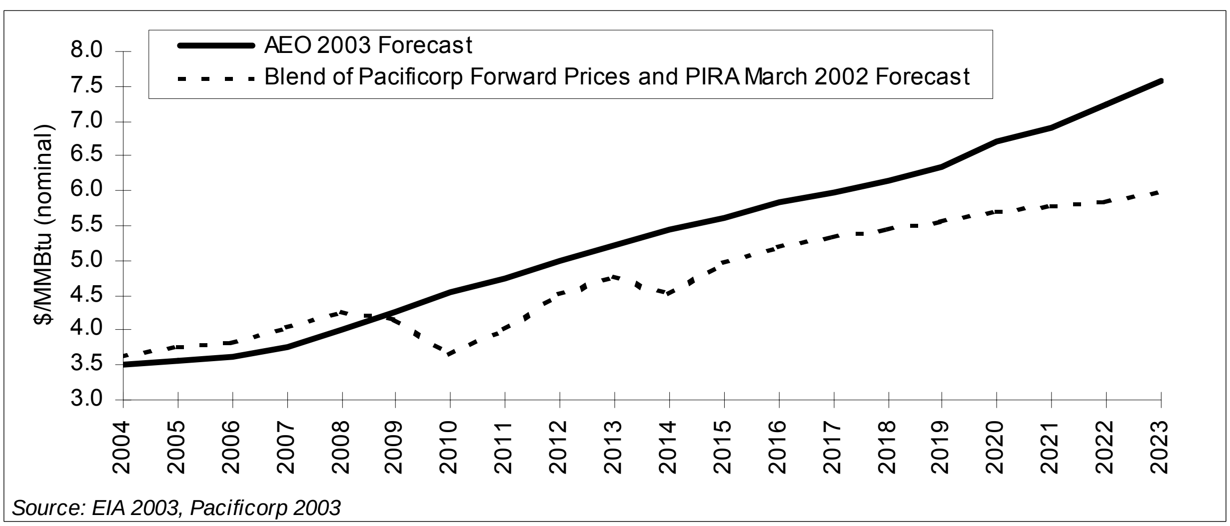

Figure 20. Pacificorp Gas Price Forecast (Utah) vs. AEO 2003 Forecast

[49] An examination of the historic difference between natural gas prices delivered to electricity generators in Utah and nationwide revealed no discernible or statistically reliable basis difference. Hence, the price series shown are unadjusted. Since PacifiCorp's 2003 IRP was released in January 2003, we used price forecasts from AEO2003.

Similarly, Figure 21 plots two forecasts of natural gas prices at the Sumas hub, as used in various drafts of Puget Sound Energy's (PSE) 2003 resource plan, against the basis-adjusted AEO 2003 reference case gas price forecast.[50] Both PSE forecasts use actual forward market prices in 2004, and rely on long-term forecasts from PIRA (released on September 13, 2002 and January 17, 2003) from 2005 on. The story is similar to that shown in Figure 20: the PSE PIRA-based forecasts are above the EIA forecast for the first few years, but then fall well below the EIA forecast in later years. Again, over a 20-year period, the gas price forecast used in the latest draft of PSE's resource plan (i.e., PIRA 01/17/03) averages $0.39/MMBtu below the EIA forecast.

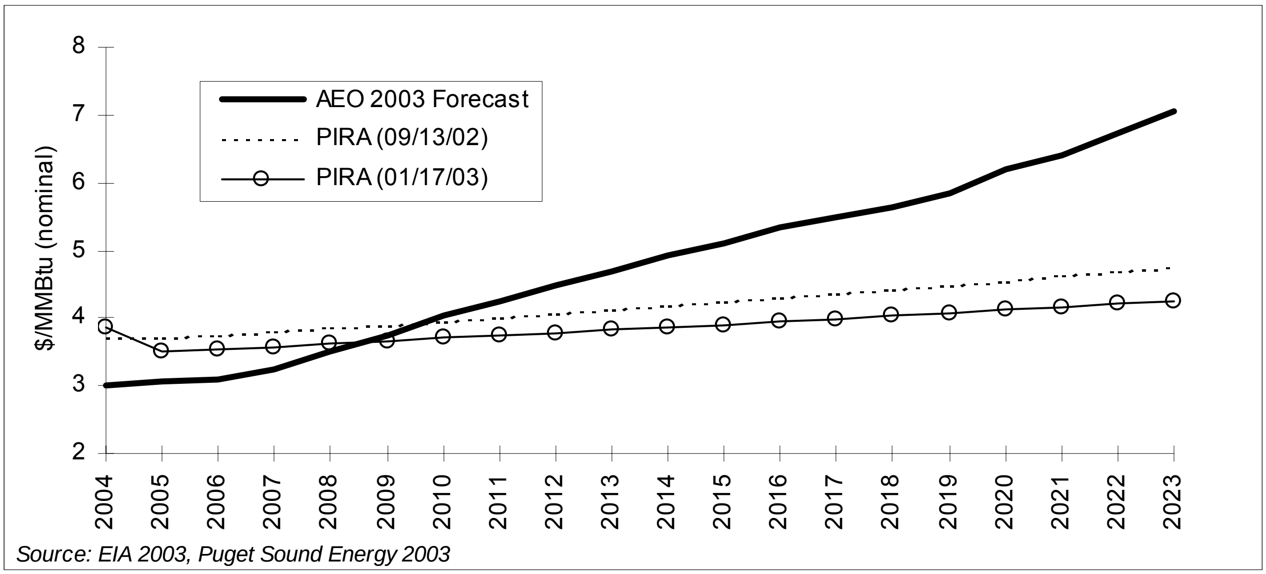

Figure 21. Puget Sound Energy Gas Price Forecast (Sumas) vs. AEO 2003 Forecast

Finally, Owens (2003a, 2003b) reveals that Platts' long-term forecast of Henry Hub gas prices (generated in early 2003) averages $3.54/MMBtu (in 2003 dollars) through 2020. In comparison, the EIA's AEO2003 forecast of gas prices delivered to electricity generators from 2003 to 2020 averages $3.97/MMBtu (in 2003 dollars), which, when adjusted to Henry Hub terms by subtracting the historic basis differential of $0.38/MMBtu (as described in Section 4.1), yields an average Henry Hub forecast of $3.59/MMBtu – slightly higher than, though essentially the same as, Platts' forecast.

5.3 Summary

The evidence presented above suggests that in recent years the EIA reference case forecast has typically been higher – and often substantially so – than most other forecasts that are commonly used by utilities and others trying to predict gas prices. These findings suggest that the premiums observed relative to the EIA forecasts in Chapter 4 would be *even larger* when comparing forward prices to some of the other forecasts presented above. Utilities and others that have used these other (i.e., non-EIA) forecasts to compare fixed-price renewable to variable-

[50] We assume a basis of -$0.18/MMBtu from Henry Hub to Sumas, taken from NWPCC (2002). Puget Sound Energy's 2003 IRP was released for comment on April 30, 2003.

price gas-fired generation over the past three years have therefore made comparisons that are arguably even more "biased" in favor of gas-fired generation than those resulting from EIA-based comparisons (presuming that long-term price stability is desirable). For example, the gas price forecast used by Idaho Power in its 2002 resource plan has been shown to be, on average, *$1.29/MMBtu* below natural gas forward prices at that time. This translates to a 0.9¢/kWh difference at an aggressive heat rate of 7,000 Btu/kWh; had Idaho Power opted to use forward market data rather than forecast data, comparisons between renewable and gas-fired generation would have looked significantly different.

One potential exception to this general trend is a December 2002 California Energy Commission (CEC) forecast for prices at the Southern California Border (CEC 2002), which matches or exceeds the prices contained in the 7-year gas supply contract between Williams and the DWR (presented in Section 4.3), and by extension exceeds the EIA's forecast as adjusted for that location using the basis assumptions of NWPPC (2002). Interestingly, NWPCC (2002) has also noted that the CEC forecast appears to be aggressive relative to its own forecast as well as others that it examined from the EIA, the Gas Research Institute, DRI-WEFA, and ICF.[51] In late May 2003, however, the CEC (2003) released an updated gas price forecast, which, while higher than its December 2002 forecast, is well below the relevant prices implied by the NYMEX futures strip at that time (implying a premium of similar magnitude to those calculated in Chapter 4). Thus, with a December 2002 forecast that is largely consistent with or even higher than forward prices, and a May 2003 forecast that is well below forward prices, it is difficult to draw conclusions regarding the CEC forecasts.

Interestingly, many of the utilities whose resource plans we examined above have substituted actual forward market prices for the first few years of the long-term price forecast. This again raises the question of premium term structure, as discussed earlier in Section 4.4. If the average premiums we have calculated are heavily "front-loaded" (i.e., exhibit an inverted term structure), then perhaps utilities are in fact accounting for a substantial fraction of the levelized premium by substituting forward market prices for the first few years of the forecast period. As was the case in Section 4.4, however, we are unable to draw any definitive conclusions about this prospect, given our limited data set and the conflicting (or at least inconclusive) information contained therein.

[51] The NWPPC analysis also found, as we have, that the EIA reference case trended towards the top of the range of these forecasts.

6. Potential Explanations for Empirical Premiums

How can one explain the existence of price premiums as high as $0.8/MMBtu over 10 years relative to EIA gas price forecasts, or *even higher* relative to other gas price forecasts, as found in Chapters 4 and 5? At least three different explanations could either partially or wholly account for such sizable differences between natural gas forwards and forecasts:

1) **Hedging is not costless.** If this is true, then one might expect forward natural gas prices to trade at a premium relative to industry-standard forecasts of future spot natural gas prices, with the premium representing the incremental cost of hedging. Such incremental costs could reflect the presence of a risk premium, caused either by *negative net hedging pressure* (i.e., gas consumers hedging more than gas producers) or *systematic risk in natural gas prices*, as measured by the Capital Asset Pricing Model (CAPM). Alternatively, the incremental cost of hedging could reflect high *transaction costs*, manifested in wide bid-offer spreads that ensure that the long (short) hedger always pays (receives) more (less) than the "true" (e.g., mid-market) price. Under this explanation (that hedging is not costless), the premiums observed in Chapter 4 might be considered the "hedge value" of renewable generation; i.e., renewable generation provides price stability without incurring these "incremental" hedging costs.

2) **The forecasts are out of tune with market expectations.** Under this explanation, the forecasts (not just the EIA's, but instead virtually all of the forecasts we have examined) themselves are at issue, and are biased downwards relative to the market's expectations of future gas prices, at least over the last three years. If this is true, then our empirical observations of premiums may not necessarily indicate that there is an incremental cost of hedging per se. In other words, forward prices may in fact be unbiased estimators of future spot prices, and the premiums we have observed may simply be due to the use of forecasts that have been seriously out of tune with market expectations over the last three years. This, of course, calls into question the use of these forecasts for *any* purpose over the last three years, and strongly suggests replacing forecast prices with forward prices where available.

3) **Other data issues are driving the premium.** Two other data problems might also be of some concern. First, the forward prices we sampled might be distorted upwards (e.g., due to thin markets and/or price manipulation), which could artificially create or inflate a premium over price forecasts. Second, if we sampled forward prices earlier or later in time than when the forecasts were generated, then the observed premiums could simply be the result of a fundamental change in market expectations in the interim.

Below we assess each of these three broad possibilities in turn. We find none of them to be either fully satisfying or easily refutable; it may be that some combination of factors is at work. Regardless of the explanation, however, the fundamental implication of our analysis is largely unchanged: if long-term price stability is valued, then when comparing the cost of variable-priced gas-fired generation to fixed-price renewable generation, one should not rely on uncertain gas price forecasts as fuel price inputs. Instead, forward prices are the correct basis for comparison.

6.1 Hedging is Not Costless

At first glance, one might hypothesize that the premiums observed in Chapter 4 simply reflect the high degree of price volatility in the natural gas market and the incremental amount that gas consumers are willing to pay above and beyond gas price forecasts 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. There are, however, at least three scenarios that support the idea of a natural gas consumer having to pay a premium to hedge gas price risk: net hedging pressure, systematic risk in natural gas prices, and transaction costs. Below we consider each of these in turn.

6.1.1 Negative Net Hedging Pressure

The idea that forward prices contain embedded risk premiums (positive or negative) was first introduced by Keynes (1930), who argued that *hedgers* who use futures markets to mitigate commodity price risk must compensate *speculators* for the "insurance" that they provide. In a market dominated by short (long) hedgers, resulting in positive (negative) *net hedging pressure*, compensation comes in the form of futures prices that are lower (higher) than the expected spot price, thereby enabling speculators to earn a positive return simply by buying (selling) futures contracts (i.e., taking the opposite position from the hedger) and maintaining that position to maturity.

For example, if, in aggregate, natural gas producers desire to hedge more strongly than do natural gas consumers, then there will be *positive net hedging pressure* – i.e., more hedgers seeking to sell futures contracts than there are seeking to buy futures contracts. Speculators (i.e., traders with no underlying position in the commodity) will step in and correct this imbalance by purchasing the excess contracts yet to be sold. Keynes' theory holds that in return for providing this service, speculators will require compensation in the form of futures prices that are *below* the expected spot price. Thus, simply by holding the futures contract to expiration, the speculator will make a positive return (because he effectively purchased the commodity for less than he can sell it for at expiration).

Alternatively, if, in aggregate, natural gas producers are less concerned about hedging than are natural gas consumers, then there will be *negative net hedging pressure* – i.e., more hedgers seeking to buy futures contracts than there are seeking to sell them – and speculators will require compensation in the form of futures prices that are *above* expected spot prices. Since this is essentially the outcome we have observed in Chapter 4 (i.e., forward prices trading above price forecasts, which might be thought as representing the expected spot price), then Keynes' theory might be considered a plausible explanation for our results if there was in fact *negative net hedging pressure* in early November 2000, 2001, and 2002 (when the comparisons from Chapter 4 were made).

Over the years a number of studies have attempted – with mixed results – to empirically confirm (or refute) the existence of risk premiums in futures prices by examining the returns to speculators.[52] Much of this work, however, has been based on a strict application of Keynes' theory, which, among other things, assumes that hedgers (i.e., characterized mainly as producers who are long the physical commodity) will be net short futures (i.e., they will be selling futures) and that speculators will therefore be net long futures (i.e., they will be buying futures). This results in positive net hedging pressure, and futures contract prices that should be below expected spot market prices. Under this constraint, one need only test for a positive return to holding futures contracts to see whether speculators have earned a risk premium.

As noted by Chang (1985), however, a number of researchers have relaxed this constraint in recognition that both producers *and* consumers hedge, and that net hedging pressure may therefore not always be positive (i.e., hedgers as a group may not always be net short). Such researchers have generally incorporated information about the aggregate net position of hedgers into their analysis, checking for positive futures returns when net hedging pressure is positive, and negative futures returns when net hedging pressure is negative. Though results remain inconclusive, the relaxation of the assumption that speculators are net long has generally led to results, as reported in Chang (1985) and Hull (1999), that are more supportive of Keynes' notion of a risk premium (positive or negative) embedded in futures prices.[53]

To test whether the premiums observed in Chapter 4 could be the direct result of negative net hedging pressure, Figure 22 depicts net hedging pressure (in terms of open interest as well as number of hedgers) from 1999 through the present.[54] Though largely positive over this period,[55]

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[52] See, for example, Houthaker (1957), Telser (1958), Cootner (1960), Gray (1961), Dusak (1973), Chang (1985), Fama and French (1987), Hirshleifer (1988), Herbert (1993), Walls (1995), de Roon et al. (2000), Buchanan et al. (2001), Bessembinder and Lemmon (2002), Pirrong and Jermakyan (2001), and Longstaff and Wang (2003). While the risk premium question was not at the heart of several of these studies, all present empirical information relevant to the debate. Also note that Herbert (1993) is the first of the studies listed above to specifically examine an energy commodity (natural gas), and that virtually all of the studies listed thereafter focus exclusively on either natural gas or electricity (with the exception of de Roon et al. (2000), who look at a wide range of commodities).

[53] For example, Houthaker (1957), Cootner (1960), Carter et al. (1983), and Chang (1985) all relax the "net long" assumption and find empirical evidence of risk premiums embedded in futures prices. Similarly, Bessembinder and Lemmon (2002) develop an equilibrium model that allows net hedging pressure to be either positive or negative, depending on both the variance and distribution (i.e., skewness) of wholesale electricity prices. In testing their model, they – along with Pirrong and Jermakyan (2001) and Longstaff and Wang (2003) – find evidence of significant risk premiums in the PJM day-ahead wholesale electricity markets.

[54] The data comes from the weekly *Commitments of Traders* reports published by the Commodity Futures Trading Commission (CFTC). Traders are classified as "commercial" or "non-commercial" depending on whether their futures positions in a given commodity are used for hedging or speculative purposes, respectively. All long and short futures positions that exceed a minimum threshold (i.e., "reportable positions") are allocated among commercial and non-commercial traders; the remaining "non-reportable" long and short positions are derived by subtracting reportable positions from total open interest. Net hedging pressure is defined as the difference between short and long reportable open interest among commercial traders divided by total open interest (the number of short and long traders can be substituted for open interest). Even though in aggregate the futures market is a zero sum game (i.e., the total number of long positions must equal the total number of short positions), the *Commitments of Traders* reports provides an indication of the breakdown of positions among market players (e.g., long hedgers, short hedgers, long speculators, short speculators) that is useful in assessing net hedging pressure. Commercial traders (i.e., hedgers) regularly account for 60-75% of the open interest in the natural gas futures market.

net hedging pressure clearly swings around quite a bit, and is negative at times. Of particular interest to this study is the fact that during two of the three periods in which we sampled forward prices (early November 2001 and 2002, depicted by the shaded bars), net hedging pressure was either neutral (i.e., close to zero) or slightly negative (i.e., meaning that long open interest outnumbered short open interest among hedgers). In the third sample period – November 2000 – net hedging pressure was clearly positive, though not nearly to the degree seen earlier in that and the previous year.

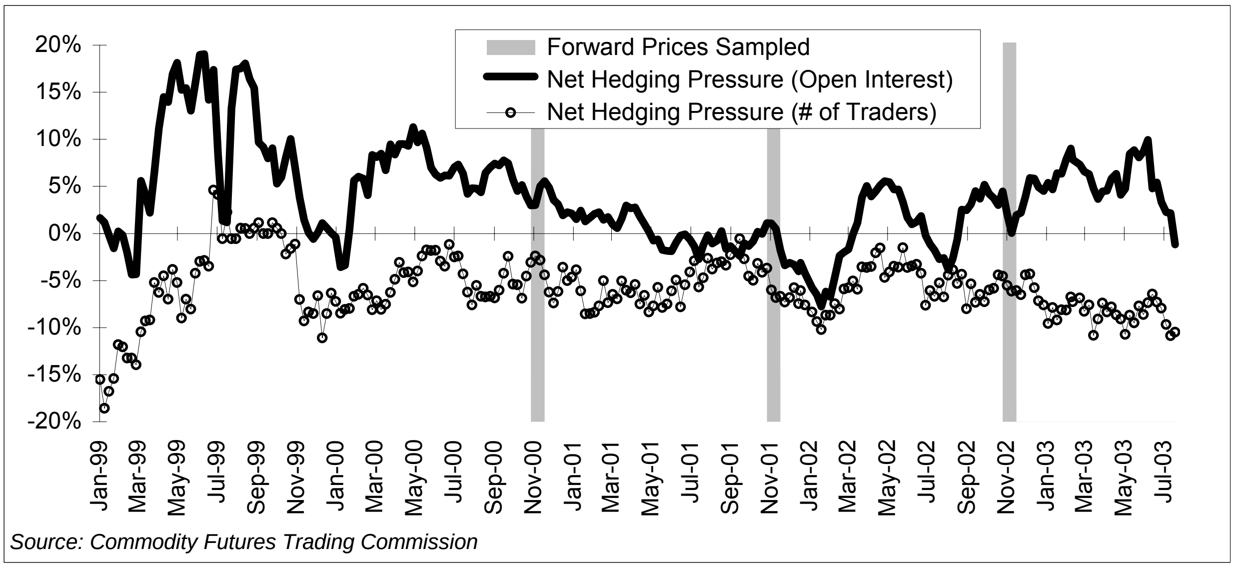

Figure 22. Net Hedging Pressure in the Natural Gas Futures Market, 1999-Present

Thus, while Figure 22 does not support the idea that negative hedging pressure is directly responsible for the premiums observed in Chapter 4, it does show a notable lack of *positive* net hedging pressure during our sample period. In other words, net hedging pressure appears to provide little support either for *or* against our findings of significant premiums in the natural gas market over the past three Novembers.

6.1.2 Systematic Risk in Natural Gas Prices

Setting aside net hedging pressure and the returns of speculators, 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

[55] Note that in terms of the number of traders, net hedging pressure has been primarily *negative* over this period. This dynamic – largely positive net hedging pressure in terms of open interest combined with largely negative net hedging pressure in terms of the number of traders – suggests the presence of a few large natural gas producers, and a greater number of smaller (in aggregate) natural gas consumers, hedging their respective risks. It is not immediately clear whether this implied market composition has any bearing on the premiums observed in Chapter 4 of this paper; an interesting question might be to examine whether information asymmetry, transaction cost theory, or strategic trading behavior can shed any light in this regard.

form of the Capital Asset Pricing Model (CAPM).[56]

While CAPM was originally derived as a financial tool to be applied to investment portfolios, its basic 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,"[57] 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 even if both consumers and producers shared identical expectations of future spot gas prices, then producers would still require – and consumers would be willing to pay – a premium over expected spot prices in order to lock in those prices today.[58] 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 contract prices (as presented in Chapter 4). 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 findings from Chapter 4.

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

[57] 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).

[58] It is worth noting here that gas producers and consumers often end up transacting with a "market maker" (e.g., Enron or Williams) rather than each other when establishing a long-term hedge. To the extent that the market maker is just a "middle man" or intermediary between producers and consumers, however, CAPM should still apply. For example, legend has it that Enron's gas unit never ended the day with a net open position on its books, having effectively "laid off" every transaction to another counterparty. If this is true – i.e., that Enron and others merely facilitate transactions between producers and consumers (making money off of the spread), rather than taking an outright position themselves – then producers and consumers can effectively be though of as transacting with one another (albeit through a third party), and CAPM should still be applicable.

6.1.2.1 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 of -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 surrounding the beta of energy commodities has focused on crude oil, whose price should be at least moderately correlated with natural gas prices. Sadorsky (1999) and Papapetrou (2001) both conclude that there is a negative correlation between changes in oil prices and stock returns (i.e., that oil exhibits a negative beta). Sauter and Awerbuch (2002) provide an extensive survey of the literature regarding oil's impact on both the economy and stock markets, while Awerbuch (2003) estimates that the historical betas of coal, gas, and oil in the European Union are on the order of -0.4, -0.1, and -0.05, respectively.[59]

On the other hand, Pindyck (2001) – though not specifically investigating beta – notes (without citation) that estimates of beta for crude oil have been 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. While qualitatively plausible, this intuition that strong economic growth puts upward pressure on commodity prices (resulting in a positive beta) is no more believable than the opposing view that high commodity prices put a damper on economic growth (resulting in a negative beta) – both interpretations merely represent successive phases of the economic cycle.[60]

6.1.2.2 Our Estimate of Beta[61]

Seeking an updated estimate of the beta of natural gas, we regressed historical percentage changes in natural gas prices delivered to electricity generators (from the EIA) against historical

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[59] It is somewhat counterintuitive that the beta of coal is found to be more negative than the beta of gas, given that the price of natural gas is generally perceived to be much more volatile than the price of coal.

[60] This ambiguity brings to light two problems that arise in estimating beta using CAPM – defining what constitutes "the market" (i.e., the stock market or the broader economy), and using coincident regressions to describe relationships that are dependent on lead/lag cycles. For example, Pindyck's intuition that economic growth puts upward pressure on industrial commodity prices implies a positive beta with *the economy*. Yet if the stock market tends to anticipate economic cycles, then the stock market may begin to decline just as economic growth is pushing commodity prices higher, implying a negative beta with *the stock market*. Moreover, if the stock market's lead time over the economy undergoes a long-term secular shift (e.g., as access to information improves), historic estimates of beta may not hold much meaning for the future.

[61] Note that while we believe the methodology presented in this section to be accurate and representative of the approach that others have taken in estimating the beta of commodities (see, for example, Kahn and Stoft 1993, Awerbuch 1993, and Dusak 1973), we readily acknowledge that our analysis could be more rigorous. Given, however, that our interest in the beta of natural gas is only secondary in nature – i.e., intended to provide support for empirically observed premiums, rather than to definitively conclude (in the absence of empirical data) that such premiums must exist – we believe the degree of precision is appropriate.

percentage changes in the S&P 500 index. We chose to work with *delivered* prices (rather than *wellhead* prices) in an attempt to capture the full risk facing gas-fired generators: volatility in both wellhead prices and transportation costs.[62] The EIA delivered price series, however, is derived from FERC Form 423, which includes spot purchases as well as some firm and interruptible contracts. While it is not clear to what degree these contracts are fixed-price or indexed, to the extent they are fixed-price and for a lengthy term (a spot check of several months of reported data uncovered one contract out to June 2006), their inclusion in the average price is likely to dampen price volatility, and perhaps distort our estimate of beta. On the other hand, using wellhead prices clearly ignores volatility in transportation costs, thereby not taking into account the full risk facing gas-fired generators. While neither price series is ideal, delivered prices appear to more closely match our needs, and will be the focus of the discussion from here on.[63]

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.

Figure 23 graphically displays our estimate of beta over time. The dashed line represents a "cumulative" estimate of beta, resulting from progressively longer-term regressions as one moves forward in time.[64] 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.[65]

As shown, our cumulative estimate of beta (the dashed line) is fairly stable over time, typically ranging from -0.2 to -0.4, yet coming to rest in 2002 at -0.1 – lower in magnitude than estimates from the early 1990s,[66] but still slightly negative. 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 oscillated between negative

[62] As demonstrated during the California energy crisis of 2000/2001, locational basis risk can be substantial: while Henry Hub gas prices peaked at around $10/MMBtu, prices delivered to the Southern California Border reached nearly $60/MMBtu (Bernstein et al. 2002).

[63] That said, we did (as a test) perform the regression using wellhead prices. This yields similar results to those obtained from delivered prices, although the *wellhead* beta appears to be more negative than the *delivered* beta in the early years, and more consistent with the findings of Kahn and Stoft (1993).

[64] 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 23-year regression in 2002.

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

[66] 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.

and positive territory. Thus, while the cumulative beta shown in Figure 23 appears to have historically been negative, it would be unwise to conclude that this will always be the case.

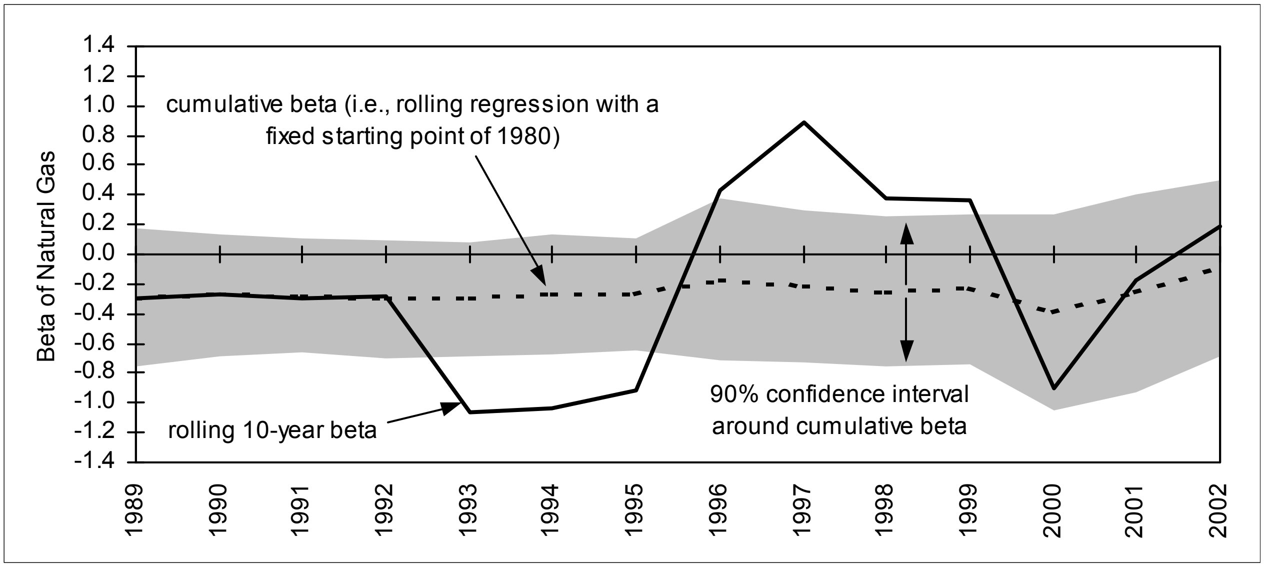

Figure 23. Estimate Of Beta Of Natural Gas Delivered To Electricity Generators (As Regressed Against The S&P 500)

6.1.2.3 Reconciling Our Estimate of Beta with Our Empirical Premiums

Using the forward price data and EIA reference case gas price forecasts presented earlier in Chapter 4, it is possible to back into empirical estimates of the beta for natural gas. To do this, one must assume that the forward prices are "riskless" (i.e., known in advance and able to be locked in), while the price streams represented by the EIA gas forecasts are "risky" (i.e., merely a forecast and bound to be wrong). One then calculates the present value of both price streams – the forward market 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 forward market 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.[67]

Performing this exercise using the forward market prices and EIA reference case forecasts presented in Chapter 4, and data on the historic returns of stocks and T-bills going back to 1926 from Ibbotson (2002),[68] we arrive at the various estimates of beta presented in Table 5.

[67] Since by definition $R_{risk\text{-}adjusted} = R_{risk\text{-}free} + ß * \text{Market Risk Premium}$, then $ß = (R_{risk\text{-}adjusted} - R_{risk\text{-}free})$ / Market Risk Premium.

[68] Ibottson (2002) calculates that the average compound annual return of T-bills and large stocks (similar to the S&P 500) from 1926 through 2001 is 3.8% and 10.7% respectively, which yields a "market risk premium" (i.e., the average annual return of stocks over bills) of 6.65% (i.e., (1+10.7%)/(1+3.8%)-1 = 6.65%).

Table 5. Empirical Estimates of the Beta of Natural Gas

	2-Year	5-Year	6-Year	7-Year	10-Year
Enron/AEO2001	-1.80	-1.23	*N/A*	*N/A*	-0.66
Enron/AEO2002	-2.39	-0.98	*N/A*	*N/A*	-0.40
NYMEX/AEO2003	-1.88	-0.79	-0.59	*N/A*	*N/A*
Williams/AEO2003	-1.43	-0.63	-0.48	-0.36	*N/A*

The empirical estimates of beta presented in Table 5 are, at least over the longer-term forward contracts, close to the regression estimates presented in Figure 23, which estimate betas of -0.40 through 2000, -0.26 through 2001, and -0.10 through 2002. While this degree of similarity is reassuring, it is also evident that the shorter-term forward contracts yield progressively higher estimates of beta (as high as –2.39 for the November 2001 2-year swap) as the contract term declines, which is somewhat less reassuring.[69]

As theoretically appealing as CAPM may seem, and as consistent as its results are with what we have observed empirically, we are nevertheless hesitant to place too much faith in CAPM as the sole explanation for our empirical findings, for several reasons. First, it is likely that many gas market participants are unfamiliar with CAPM, making it hard to believe that CAPM is regularly and explicitly incorporated into decision-making processes. Furthermore, CAPM formally requires that each individual's portfolio be fully diversified so that only market risk remains. Kahn and Stoft (1993) note that this may not be the case for the management of gas producing companies, whose careers and reputation (if not portfolios – witness Enron's retirement plan, which was heavily invested in Enron stock) are closely tied to the profitability of the firm, and who therefore may view gas price volatility as risky even if it is negatively correlated with the market.

6.1.3 Transaction Costs

Transaction costs, which represent the inescapable cost of doing business, provide another possible explanation in support of the idea that those hedging gas price risk will incur incremental costs relative to market expectations of future spot prices. In financial markets, transaction costs are manifested in the "bid-offer spread": the spread between the price at which one is willing to buy (bid) and sell (offer) a product. To execute a deal with minimal price risk (i.e., the risk that the market price rises (falls) while one is trying to buy (sell)), one must typically "cross" the bid-offer spread (i.e., pay the offering price (if buying) or accept the bid price (if selling)). Since the "true" market price lies somewhere in between the bid and the offer, crossing the bid-offer spread to execute a deal results in transaction costs being incurred (i.e., paying more, or receiving less, than the "true" market price). For analytical purposes, the size of the transaction cost of dealing (i.e., buying or selling) in a market is typically considered to be half the size of the bid-offer spread in that market (under the assumption that the "true" market price lies half way in between the bid and the offer).

[69] Perhaps over shorter terms (i.e., 2 years), the comparison of forward market prices 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.

In liquid markets, transaction costs (i.e., bid-offer spreads) are typically very small, and of little concern. In less-liquid markets (or even thinly traded segments of otherwise liquid markets), however, bid-offer spreads can be quite wide, and can have a more significant impact on the cost of transactions. Figure 24 depicts a hypothetical situation where this is the case: the difference between the dashed and starred lines represents the bid-offer spread (also depicted by the double-headed arrow), which grows wider the further out on the forward curve one trades, reflecting progressively poorer liquidity. The shaded area represents the premium over the mid-market price that one would have to pay in order to purchase the hedging instrument.

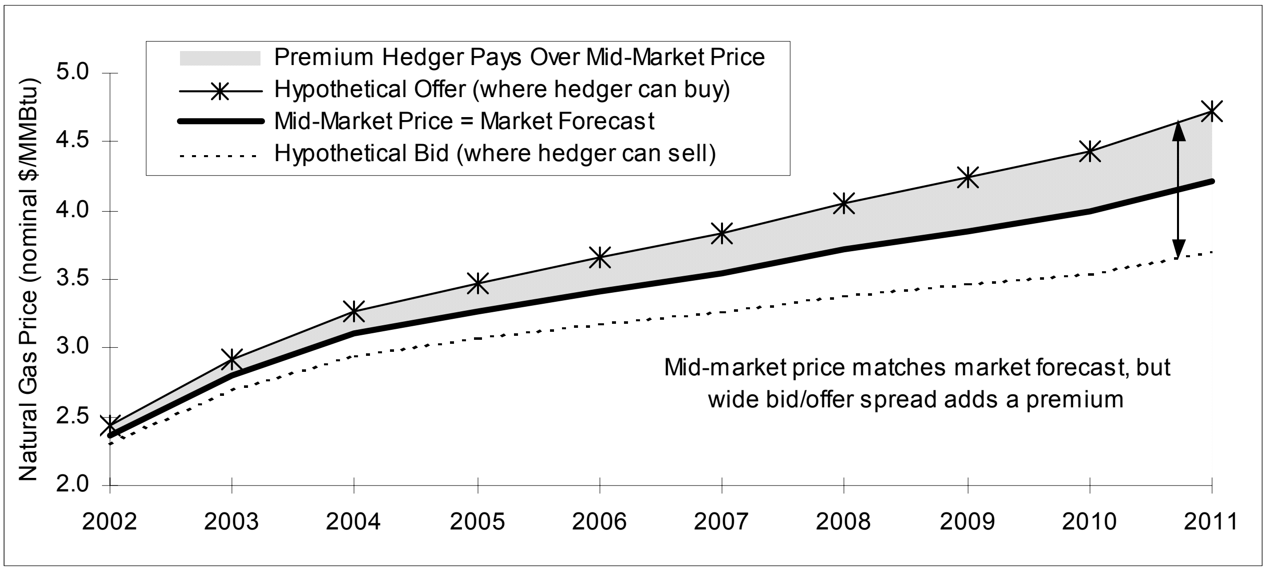

Figure 24. Hypothetical Example of Premium Stemming from Transaction Costs

Note that in Figure 24, the mid-market forward price curve (thick solid line) perfectly matches the market forecast of future spot prices,[70] so the bid-offer spread is the sole source of any price premium. One could just as easily imagine a situation in which the mid-market forward price curve exceeds the market forecast (e.g., the situation explained by CAPM in the previous section), while the bid-offer spread adds to the implicit risk premium. Or, alternatively, even if the forward curve is priced *below* the market forecast, a large enough bid-offer spread could still result in a net premium.

How close to reality is Figure 24? That is, how high are transaction costs in the long-term natural gas market? While we do not have sufficient data on long-dated forwards to say, we can at least examine bid-offer spreads in the "highly liquid" but shorter-term NYMEX futures market. Figure 25 depicts typical bid-offer spreads over the first 36 contracts, plotted against "open interest" for the entire strip of 72 contracts.[71] For a trade size of 30 contracts executed

[70] This is akin to a situation in which beta = 0, or else CAPM simply does not apply.
[71] "Open interest" represents the number of open or outstanding contracts to the exchange (i.e., contracts that have not been closed out either through an offsetting position or via delivery). Volume – i.e., the number of contracts that changed hands in a given day – is perhaps a better measure of liquidity, though is also more sensitive to the particular day chosen (e.g., volume may be very light on the Friday before a 3-day holiday weekend, while open interest will likely be relatively unchanged from its normal levels).

under normal market conditions,[72] bid-offer spreads in the first four futures contracts (i.e., representing delivery in each of the next four months) are immaterial. Moving beyond these first few very liquid contracts, however, the bid-offer spread typically doubles for the next nine contracts (as liquidity – proxied here by open interest – declines), then doubles again for the subsequent eleven contracts, before more than doubling for the next twelve contracts (representing a total of 36 months or 3 years). Beyond these first 36 months (NYMEX gas futures are listed out 72 months), NYMEX gas futures are *very* thinly traded (open interest essentially drops to zero), making it costly or even difficult to complete a trade of this size (Waller 2002).[73]

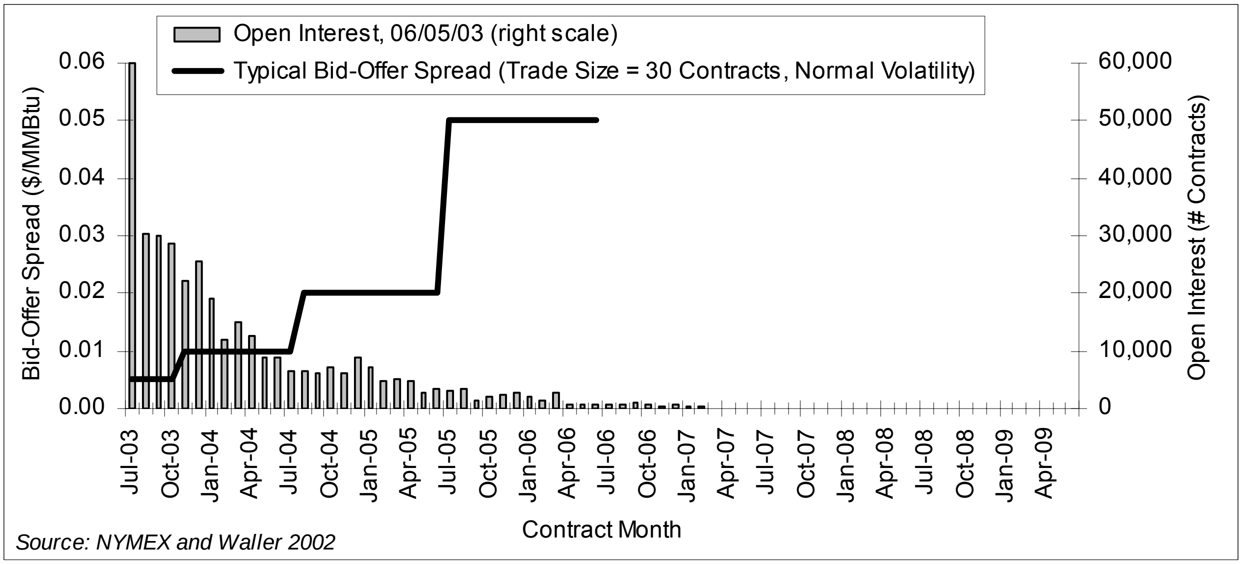

Figure 25. Typical Bid-Offer Spread and Open Interest for NYMEX Natural Gas Futures

Although the bid-offer spread shown in Figure 25 does widen dramatically as liquidity declines along the strip, the absolute numbers shown (<2% of the contract price at its widest) are admittedly small. That said, the reason the bid-offer spread in Figure 25 does not extend beyond 36 months is because beyond this point there is very little liquidity on which to base a reliable estimate. In other words, beyond 36 months, there is not necessarily "a market" per se, and the cost of deal execution depends largely on the ability to locate a willing buyer or seller, which may require significant price concessions at times.

[72] Trade size and market conditions are relevant because the bid-offer spread will increase with trade size as well as during periods of heightened price volatility. By way of reference, 30 contracts per month is roughly equivalent to the amount of gas needed to fuel an 85 MW combined-cycle gas turbine (heat rate of 7,000 Btu/kWh) operating at a 70% capacity factor. A gas plant that is twice as large (170 MW) would obviously require twice as many contracts (i.e., 60) to *fully* hedge gas price risk (or could use the original 30 contracts to hedge *half* of its risk).

[73] Again, the NYMEX has a somewhat involved procedure for calculating settlement prices for such illiquid contracts that involves considering the spread relationships between the contract in question and more actively traded contracts. Without considering the merits of this approach, it is worth noting that in the absence of actual trades (or at least strong bids and offers) it may not be possible to buy or sell a long-dated gas futures contract at or near the NYMEX settlement price.

Given the steep slope of the bid-offer spread curve over the first 36 contracts (i.e., 36 months), one would expect deals with longer maturities to have even higher transaction costs. Unfortunately, we do not have sufficient data to confirm this notion. The swap prices quoted in Section 4.1 were Enron offers; while we do not have corresponding bid prices from the same trading days by which to calculate indicative bid-offer spreads, we do have Enron bid prices for the 5-year swap from the *previous* trading days (unfortunately, bids for 10-year swaps are not listed). These data – Monday's bid price and Tuesday's offer price – imply that the bid-offer spread (at least on an indicative basis) on a 5-year swap is comparable to that shown in Figure 25.[74] When asked for an indication of a bid-offer spread on a *20-year* natural gas swap, however, one Enron gas trader estimated that *$0.50/MMBtu* would be a reasonable ballpark estimate. While the sheer magnitude of this spread is most likely an indication that no one trades natural gas swaps out that far, it nonetheless exemplifies the impact that transaction costs can have in illiquid markets.

In fact, all of the discussion above serves to illustrate a simple point: using financial markets to hedge for longer than a few years can potentially result in significant transaction costs, and the more illiquid and inefficient the market, the higher the transaction costs will be. While we are focusing on natural gas markets, this statement may be particularly true in the thinly traded electricity markets.

One advantage of using renewables to manage price risk, therefore, is that there is little or no need to incur wide bid-offer spreads on conventional futures or forward hedge products (though, of course, contracting for renewables will involve its own transaction costs). The magnitude of the avoided transaction costs could be considered at least a partial proxy for the "hedge value" of renewables.

6.2 The Forecasts Are Out of Tune with Market Expectations

Another possible explanation for our empirically derived premiums between gas forwards and forecasts over the last three years is related to the forecasts themselves. Specifically, the forecasts may have been biased downwards or otherwise inconsistent with market expectations of spot gas prices over the past three years (which has, after all, been a period of considerable market instability and turmoil). Proponents of this explanation might argue that forward prices should represent the market's view of future spot gas prices, and therefore that there is no explicit, incremental cost of hedging gas price volatility. Therefore, any real (i.e., not due to data problems) positive difference between gas forwards and gas price forecasts must represent a downward bias in the forecasts relative to the market's view of future spot prices. Furthermore, given that Chapter 5 found that EIA's reference case gas price forecasts have been at the high end of the range relative to other common industry forecasts over the last three years, this explanation directly takes issue not only with the EIA reference case forecast, but also with

[74] This estimate assumes that the market price of the 5-year swap did not move from one day to the next. Given the duration of the swap, this is likely to be a reasonable assumption.

virtually all other publicly available gas price forecasts over the last three years.[75]

For example, just as we have found, Ferguson and McMahon (2002) also note that "contracts for future gas deliveries are trading at prices significantly higher than USEIA projections." Rather than considering the possibility of a risk premium in forward prices (i.e., the possibility discussed in Section 6.1) as the culprit, however, they instead attribute the difference to the EIA forecasts simply being unrepresentative of the market's view: "There appears to be a serious disconnect between the official [EIA] view of the future, in which conventional domestic gas is plentiful, and the industry's view" (Ferguson and McMahon 2002). As further evidence of this disconnect, the authors point to strong industry interest in both the proposed Arctic natural gas pipeline and liquefied natural gas (LNG) import terminals, and note that "The fact that industry is pursuing [these] more capital intensive alternative sources [of supply] is a good indication that industry insiders do not agree with USEIA supply projections" (Ferguson and McMahon 2002). In other words, the authors believe that the EIA forecast is inconsistent with industry's view of future gas supply and prices, which, if true, would mean that the differences between forward prices and price forecasts found in Chapter 4 may not be attributed to a risk premium or an implicit cost of hedging, but instead to "biased" forecasts.

While it is impossible to directly judge the validity of this view, we can debunk some of the suppositions that lead to its formation. Most problematic is Ferguson and McMahon's failure to adjust the EIA price forecasts for inflation, which leads them to compare *real* natural gas price forecasts (i.e., in year 2000 dollars) to *nominal* forward prices. This will obviously inflate and distort the size of any premium.[76] Failing to adjust for inflation also leads the authors to conclude that the EIA's price projections will never reach the "trigger price" at which it makes economic sense to build LNG terminals, when in fact at least the *nominal* price projections do reach this point, and the EIA supply forecast does in fact assume that LNG facilities (as well as the Alaskan pipeline) will be built, bolstering future supply. Thus, when viewed correctly in nominal terms, the EIA forecast appears to neither be as grossly out of line with forward prices as suggested by Ferguson and McMahon, nor entirely inconsistent with industry interest in building an Arctic pipeline and LNG terminals.[77]

Furthermore, whatever the merits of their arguments, Ferguson and McMahon (2002) do not have history on their side. The EIA's own evaluation of the accuracy of its past AEO forecasts has found that "Energy prices…have been far more difficult to predict than consumption, production, and net imports," and that "Typically the rate of increase in energy prices has been overestimated rather than underestimated" (Sanchez 2002). And while "Natural gas generally has been the fuel with the least accurate forecasts in consumption, production, and prices," an examination of the accuracy of past gas price forecasts (from the past twenty AEOs) reveals that, with the exception of 2000 and 2001, AEO gas price forecasts have consistently overestimated

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[75] While it is certainly possible that virtually all gas price forecasts have been biased downwards over the past three years, given likely similarities between the various models behind each forecast, the "absolute" nature of this consideration is nonetheless worth noting.

[76] Note that, as shown in this paper, a premium still exists even after proper inflation adjustments. This premium, however, is obviously not as large (or as alarming) as that found by Ferguson and McMahon (2002).

[77] Furthermore, the Arctic gas pipeline has been so politicized by the large amount of federal funding at stake that it is hard to believe that industry is acting solely on rational economic grounds when lobbying for its construction.

the actual spot price of gas for the past seventeen years (Sanchez 2002). While these historic results may in no way be indicative of future trends, the weight of history nevertheless does not lend ready support to the view that the EIA's reference case natural gas price forecast is systematically biased downwards.

Setting aside the specific arguments of Ferguson and McMahon (2002), however, it could well be that their general hypothesis is largely correct. In other words, perhaps the U.S. natural gas industry has recently run into a serious short-term supply constraint that has shifted gas prices into a new regime, and this paradigm has not been reflected in either the EIA reference case or a host of other gas price forecasts generated over the last three years. While this is certainly a plausible explanation, particularly in light of the considerable market instability and turmoil over this period, it cannot be directly supported or refuted by our data.

Another possibility is that the point of comparison is inappropriate altogether: several reviewers of a draft of this report noted that the long-term gas-price forecasts discussed herein do not even seek to represent the market's view of future spot gas prices. For example, the EIA notes that its "reference case" forecast assumes that normal inventories and weather, as well as current laws and regulations, will hold throughout the forecast period, and therefore that the reference case forecast does not necessarily reflect what the EIA believes to be "most likely." In fact, the EIA does not assign probabilities to any of the forecasts it generates, so the "high economic growth case" forecast might be considered just as likely as the "low economic growth case" forecast, for example. Furthermore, by assuming away weather, inventory levels, and regulations – all of which have a major impact on prices – the EIA notes that it is not really forecasting *prices* at all, but rather long-term equilibrium *costs*.[78]

Nonetheless, while the EIA reference case forecast may not be *designed* to represent EIA or market expectations of future gas prices, it deserves note that industry participants and energy analysts regularly use the EIA reference case projection as a "best estimate" of future energy outcomes; in fact, the EIA itself regularly uses its reference case forecast as the "base-case" forecast when evaluating the cost and impacts of energy policies. It is also evident that some utilities – one important segment of the gas market – are relying on EIA reference case forecasts as a "best estimate" of future gas prices for the purpose of long-term resource planning. Finally, it deserves mention that the above comments relate only to the EIA forecasts, and would not to our knowledge call into question our use of other gas price forecasts presented in this paper.

On a related note, another reviewer argued that reference case gas price forecasts can best be thought of as *modes* (i.e., the single scenario that the forecaster believes to be the most likely) rather than *means* (i.e., a probability weighted average of all possible spot prices), and since market expectations are by definition *mean* expectations, reference case gas price forecasts cannot represent market expectations. While this argument does not hold for the EIA reference case forecast, which as described above may be neither a mean nor a mode, the implications of this comment are nonetheless worth noting. Specifically, since gas prices are generally believed to be lognormally distributed or positively skewed, the mean must lie above the mode, meaning that true market expectations must be higher than gas-price forecasts (if those forecasts do indeed

[78] We note, however, that *Annual Energy Outlook* uses the term "price" instead of "cost" to describe its forecasts.

represent the mode). If this argument is accurate, it might explain some or all of the premium we have observed between forward prices and price forecasts. More importantly, however, this argument calls into question why utilities and others would ever directly use reference case gas price forecasts in modeling and planning exercises. By doing so, they would be *systematically underestimating* the market's expectations of future gas prices, thereby erroneously making gas-fired generation appear to be cheaper than it is likely to be on average (and, by extension, making fixed-price renewables look relatively less attractive than they are).

In conclusion, one plausible explanation for the premiums we observed in Chapters 4 and 5 is that the forecasts (not just the EIA's, but instead virtually all of the forecasts we have examined) have been biased downwards relative to the market's expectations of future gas prices over the last three years. If true, not only would this help to explain our empirical findings, it would also call into question the use of these very forecasts in resource planning processes over the last three years, and would strongly suggest replacing price forecasts with forward prices where available. Unfortunately, as with the previous possible explanation for our empirical findings (hedging is not costless), this explanation also cannot be definitively tested.

6.3 Other Data Issues are Driving the Premium

A final possible explanation for our findings is simply that our analysis is plagued by data issues that prohibit a meaningful comparison between forward prices and price forecasts. While Section 6.2 raised the possibility that forecast problems are at least partly responsible for the premium, Section 6.3.1 considers the possibility that the other half of the equation – the forward price – is upwardly biased. Meanwhile, Section 6.3.2 examines whether potential changes in the market between when the forward prices were sampled and the forecasts were generated could account for some or all of the observed premiums (regardless of the quality of the forward and forecast data). Based on our analysis below, we conclude that these two possible data problems are not likely to be severe, and that the other two explanations (costly hedging or biased forecasts) are more likely.

6.3.1 Upwardly Biased Forward Prices

If our forward price sample is biased upwards (i.e., above the market equilibrium forward price), then the premiums observed in Chapter 4 could partly or entirely result from this bias. While the possibility of bias is of potential concern for the Enron and Williams prices used in our analysis, the NYMEX prices are by definition "market" prices, and so are of less concern.[79]

The potential for price manipulation provides the greatest impetus for examining Enron and Williams prices for upward bias. This is particularly true in light of the role that both companies allegedly played in precipitating California's electricity crisis – a role that apparently involved reporting fictitious trades and deliberately misleading prices (at least by Enron). Perhaps the best way to test for price manipulation is to benchmark prices against an unbiased source (e.g.,

[79] There is potential for bias in long-dated NYMEX futures that are thinly traded (or not traded at all), for which the exchange sets a daily settlement price that may or may not be close to where an actual trade could be executed. The risk of deliberate price manipulation, however, is small for NYMEX futures contracts.

NYMEX). As shown earlier in Figure 7, Enron's 2-year swap price from November 2001 (i.e., \$3.32/MMBtu) matches 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 were representative of the broader market (confirmation of longer-dated Enron prices is not possible, as Enron was the dominant player – and in some cases the only counterparty – at the long end of the curve). Likewise, as mentioned in Section 4.3, the prices contained in the Williams contract are similar to those in the NYMEX futures strip at the time, implying that the prices within the Williams contract are also largely representative of market prices (at least during the 5-year period for which the Williams contract and NYMEX strip overlap).

To supplement the perhaps minor degree of comfort provided by these price comparisons, a few broader comments are perhaps also worth mentioning:

- Most of the allegations against Enron and Williams target questionable business practices within their wholesale electricity – not natural gas – operations. The greater liquidity and depth of the gas market makes it less vulnerable to such blatant price manipulation.
- The Enron swaps are indexed to Henry Hub, not California, gas prices. Investigations into natural gas pricing during the electricity crisis tend to focus on the factors that drove up the basis *between* Henry Hub and California to many times its usual margin. Henry Hub prices themselves have not come under any particular scrutiny.
- The Enron swap prices are sampled from two different years (November 2000 and 2001), and by the second year's sampling the crisis – at least as measured by wholesale electricity and gas prices – was largely over.

Besides the potential for price manipulation, another relevant concern is whether or not Enron swap prices from November 2001 reflect an increased credit risk premium, given that Enron was spiraling towards bankruptcy at that time. Three responses are in order. First, Figure 7 (presented earlier in Section 3.1) implies that Enron's swap prices – which, at least at the short end of the curve, were entirely consistent with NYMEX prices at that time – did not reflect credit risk in November 2001, despite the company's impending declaration of bankruptcy. Second, while the fraudulent activities that 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* empirical risk premium – should not be tainted by credit concerns. Finally, and most importantly, one must recognize that if credit risk (of the seller) were priced into Enron (or Williams) contracts, the impact would be to *reduce* prices, not raise them (i.e., the buyer would require compensation for accepting Enron's credit risk). Since we are primarily concerned with upwardly biased prices, we can safely dismiss credit risk as a potential factor skewing our results.

Hence, while it is impossible to be certain, particularly given the long-term nature of the forwards in which we are interested and the lack of liquidity at the long end of the forward curve, there is no material evidence to suggest that the prices used in our analysis are upwardly biased. In fact, it is unlikely that NYMEX prices from November 2002 were upwardly biased, and the empirical premiums based on that NYMEX data are largely consistent with those based on Enron swap and Williams gas supply contracts. Without further confirmation of the Enron and

Williams prices, however, the possibility of forward price bias cannot be entirely ruled out as a potentially viable explanation for the premiums observed in Chapter 4.

6.3.2 Timing Mismatch Between Forecast Generation and Forward Price Sampling

Our analysis presumes that the forecasters (e.g., the EIA) and the market (e.g., Enron, Williams, NYMEX) were privy to the same market information, at least in terms of time,[80] when developing their forecasts and pricing their forwards. If instead some sort of fundamental shift in the market occurred after the forecasts were finalized but before the forwards were priced, or vice versa, then the two might not be very comparable, as they would be based on a different set of underlying assumptions. Such a discrepancy in timing could, in theory, partly or wholly account for the premiums observed in Chapter 4. Perhaps the easiest way to test for this possibility is to view the behavior of long-term futures prices over the relevant time periods; if some fundamental shift in the market did occur in the interim, it would likely be reflected by a corresponding movement in long-dated futures prices.

Figure 26 shows daily NYMEX 36-month (i.e., 36th-nearby) futures prices from September through November of 2000 (thick line), 2001 (dashed line), and 2002 (thin line). The brackets depict the time period over which the EIA's gas forecast was generated in each year's *Annual Energy Outlook*.[81] The shaded area represents the period when forward prices were sampled each year: the Enron swaps were priced in the first two weeks (i.e., the 6th and 13th) of November 2000 and 2001, the Williams contract was signed on November 11, 2002, and we sampled NYMEX prices from November 4, 2002 (i.e., the day before the AEO2003 forecast was finalized).

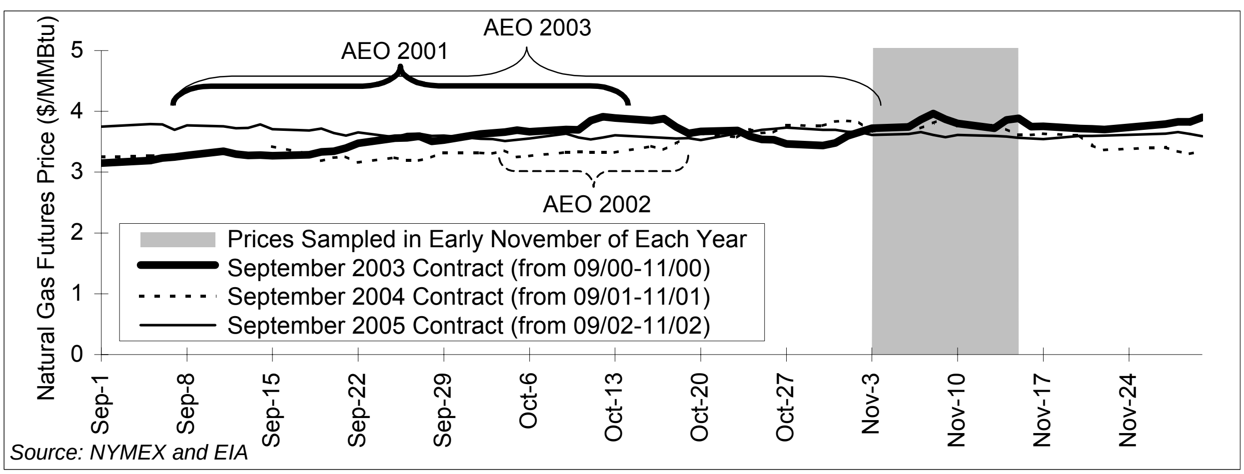

Figure 26. 36-Month Gas Futures Prices During Period of EIA Forecast Generation

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[80] Indeed, time is the only variable we can hope to control, as – even at the same moment in time – the traders (Enron, Williams, NYMEX) clearly had access to "market information" not available to the EIA, and vice versa.

[81] The AEO2001 forecast was generated on October 16, 2000, with price projections for the coming year (i.e., 2001) benchmarked to the September 2000 Short-Term Energy Outlook (STEO), which had been published on September 6, 2000. The corresponding dates for the AEO2002 forecast are October 20 (AEO) and October 4 (STEO), 2001, while the relevant dates for the AEO2003 forecast are November 5 (AEO) and September 6 (STEO), 2002.

Figure 26 reveals that long-dated futures prices in each of the three years in question were essentially unchanged from the time the forecasts were generated to the time the forwards were priced.[82] Assuming that any fundamental change in the market (i.e., a change that would impact *long-term* gas price forecasts and forward prices) over this time period would have been reflected in long-dated futures prices, and seeing no evidence of such a change, we tentatively conclude that timing is not an issue, and that the forecasts and forward price data can be considered coincident for our purposes.

6.4 Summary

Each of the three potential explanations for the existence of empirical premiums presented in Sections 6.1-6.3 is theoretically plausible, yet perhaps not fully satisfactory on its own:

1) **Hedging Is Not Costless:** While the idea that there is an implicit cost to hedging provided the original impetus for our comparison of forward prices to price forecasts (and if true, would make it easier to extrapolate our findings of a premium to other contract terms and time periods), each of the scenarios that would support such an explanation leaves something to be desired:
    - *Negative Net Hedging Pressure:* The concept of net hedging pressure creating risk premiums is controversial, and empirical efforts to confirm this theory have produced mixed results. Furthermore, while it appears as if net hedging pressure was negative or neutral (or at least not strongly positive) at the time of our comparisons, there is no particular reason to believe that long hedgers will dominate the market in the future.
    - *Systematic Risk in Natural Gas Prices:* Though theoretically pleasing and somewhat consistent with our findings, the CAPM-based explanation is also controversial, and requires a level of understanding and action among market participants that is perhaps unrealistic.
    - *Transaction Costs:* The price information we have collected implies that transaction costs – which certainly contribute to a premium – may not be sufficiently high to explain the full magnitude of the premiums observed in Chapter 4.

2) **The Forecasts Are Out of Tune with Market Expectations:** While the EIA's long-term gas price forecasts are not necessarily designed or intended to reflect market expectations of future spot prices, it is nevertheless clear that utilities and other market participants have been using such forecasts in their planning and modeling studies, thereby implicitly adopting them as their long-term price expectations. Furthermore, for one to believe that the EIA's reference case gas price forecasts have been biased downward over the past three years, one would also have to believe that *virtually all* long-term gas price forecasts generated over the past three years have been biased downward, since, as shown in Chapter 5, EIA price forecasts have generally exceeded most other concurrent forecasts during this period. While there is certainly a possibility that all fundamentals-based forecasting models "think" alike

[82] While the futures prices are obviously moving around, the degree of movement (ranging between $3-$4/MMBtu) does not appear to be distinguishable from the random "noise" that characterizes day-to-day trading, and prices are more or less at the same level in early November of each year as they were while the forecasts were being generated.

and therefore have produced similarly biased forecasts over the last three years, proving (or disproving) this theory is not possible based on the data at hand.

3) **Other Data Issues:** Finally, we have no evidence to suggest that data issues, such as upwardly biased forward prices or differences in timing between when the forwards were sampled and the forecasts were generated, are responsible for the premiums observed in Chapter 4. Without definitive proof to the contrary, we leave this possible explanation on the table, but our analysis suggests that data issues are unlikely to be the cause of our results.

Thus, no single explanation stands beyond reproach, and it is perhaps more likely that two or more of these (and maybe other) explanations working in combination are driving our empirical findings of a premium.

Regardless of the explanation for (or interpretation of) our empirical findings, however, the basic implications of our study remain the same: *one should not blindly rely on gas price forecasts when comparing fixed-price renewable to variable-price gas-fired generation contracts.* If there is a cost to hedging – whether related to net hedging pressure, CAPM, transaction costs, or some combination of the three – gas price forecasts do not capture and account for it. Alternatively, if the forecasts are at risk of being biased or out of tune with the market, then one certainly would not want to use them as the basis for investment decisions or resource comparisons if a better source of data (i.e., forwards) existed. Accordingly, in both cases, the most comprehensive way to compare resource options would be to use forward natural gas price data as opposed to natural gas price forecasts.

7. Conclusions

7.1 Summary of Analysis

Our analysis has progressed as follows:

- **Chapter 2** demonstrated that natural gas price volatility poses a major risk within wholesale electricity markets, and that in order to achieve a fuel price risk profile similar to that of fixed-price renewable generation, either the buyer (under spot, indexed, and tolling electricity contracts) or seller (under fixed-price electricity contracts) of gas-fired generation must hedge away natural gas price risk.
- **Chapter 3** concluded that natural gas futures, swaps, and fixed-price physical supply contracts are the relevant hedging instruments that provide a symmetrical payout pattern analogous to that provided by renewables. If long-term price stability is valued, then the prices that can be locked in through such contracts (i.e., "forward prices") are therefore the appropriate fuel price input to resource acquisition, planning, and modeling studies that compare – either explicitly or implicitly – renewable to gas-fired generation. Utilities and others conducting such analyses, however, tend to rely primarily on uncertain long-term forecasts of spot natural gas prices, rather than on forward prices that can be locked in with certainty.
- **Chapter 4**, therefore, compared forward prices for natural gas to long-term gas price forecasts from the EIA, and found that over the past three Novembers, forward prices have exceeded EIA reference case price forecasts by \$0.4-\$0.8/MMBtu (\$0.6/MMBtu on average) for terms ranging from 2-10 years. At an aggressive heat rate of 7,000 Btu/kWh, this "premium" translates into 0.3-0.6¢/kWh (0.4¢/kWh on average). Thus, utilities and others that have relied on EIA reference case gas price forecasts in resource acquisition, modeling, and planning exercises over the past three years have likely produced results that are biased in favor of gas-fired generation relative to fixed-price renewable generation (again, presuming that long-term price stability is an important consideration).
- **Chapter 5** demonstrated that in recent years the EIA reference case gas price forecast has typically been higher – and often substantially so – than most other forecasts that are commonly used by utilities and others trying to predict gas prices. This finding suggests that the premiums observed relative to the EIA reference case forecasts in Chapter 4 would be *even larger* when comparing forward prices to some of the other forecasts commonly used in the electricity industry. Thus, presuming that long-term price stability is desirable, utilities and others that have used these other (i.e., non-EIA) gas price forecasts to compare fixed-price renewable to variable-price gas-fired generation over the past three years have arguably been making comparisons that are *even more* "biased" in favor of gas-fired generation than those resulting from EIA-based comparisons.
- **Chapter 6** explored three potential explanations for the empirical premiums observed in Chapters 4 and 5. The first is that there may be a measurable incremental cost to hedging, potentially resulting from some combination of: (a) negative net hedging pressure, (b) systematic risk in natural gas prices, or (c) high transaction costs. The second possibility is that there is no incremental cost to hedging per se (i.e., forward prices are unbiased estimators of future spot prices), but instead that virtually all of the gas price forecasts

generated in the last three years that are presented in this report were biased downward or were otherwise inconsistent with market expectations at the time. The third possibility is that data issues, related to distorted forward prices or a critical discrepancy in timing between when the forecasts were generated and when the prices were sampled, are responsible for the observed premium. Chapter 6 found none of these three possibilities to be either fully satisfying or entirely refutable; it may be that some combination of factors is at work.

Regardless of the explanation for our empirical findings, however, the basic implication of our study remains the same: *one should not blindly rely on gas price forecasts when comparing fixed-price renewable to variable-price gas-fired generation contracts.* If there is a cost to hedging, gas price forecasts do not capture and account for it. Alternatively, if gas price forecasts are at risk of being biased or out of tune with the market, then one certainly would not want to use them as the basis for investment decisions or resource comparisons if a better source of data (i.e., forwards) existed.

Accordingly, in virtually all cases, the most comprehensive way to compare resource options would be to use forward natural gas price data as opposed to natural gas price forecasts. 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-fired generation. Of course, a true apples-to-apples comparison would also account for the many other types of risk inherent in electricity generation, some of which are specific to renewable generation (see Text Box 2, below, for a discussion one of those risks – integration costs).

7.2 An Example of the Potential Importance of These Results

The premiums observed over the past three years in Chapter 4 may have, in some cases, been enough to tip the scales away from investments in new natural gas plants and in favor of investments in renewable energy; this is especially true for wind, geothermal, and certain forms of biomass power, which in some cases have nearly (or already) achieved economic parity with natural gas-fired generation in several regions of the United States. Below we make this point visually by revisiting Figure 5 from Section 2.3, which showed how the levelized cost of energy from a hypothetical combined cycle gas plant varies over a range of gas prices. Figure 27 recreates a portion of Figure 5 (i.e., the total levelized cost of electricity from an advanced combined cycle turbine, represented by the diagonal or upward-sloping line), and compares it to the cost of wind power (represented by the horizontal shaded area) as revealed through letters of intent between the California Consumer Power and Conservation Financing Authority ("the Power Authority") and wind developers.

Specifically, in the fall of 2001, the Power Authority signed letters of intent to purchase power from 1,845 MW of wind capacity over a 10-year period. All of this wind power was to be sold at fixed prices ranging from 4-5¢/kWh, with roughly half (898 MW) costing between 4.0-4.5¢/kWh, and the remainder (947 MW) costing between 4.5-5.0¢/kWh (Bolinger and Wiser 2001). The dashed lines that extend vertically from the x-axis and are transposed (by the upward-sloping line representing the cost of gas-fired generation) to the y-axis show the levelized cost of gas (and power) based on the 10-year gas price forecast from *Annual Energy Outlook 2002* and the 10-year Enron swap price from November 2001.

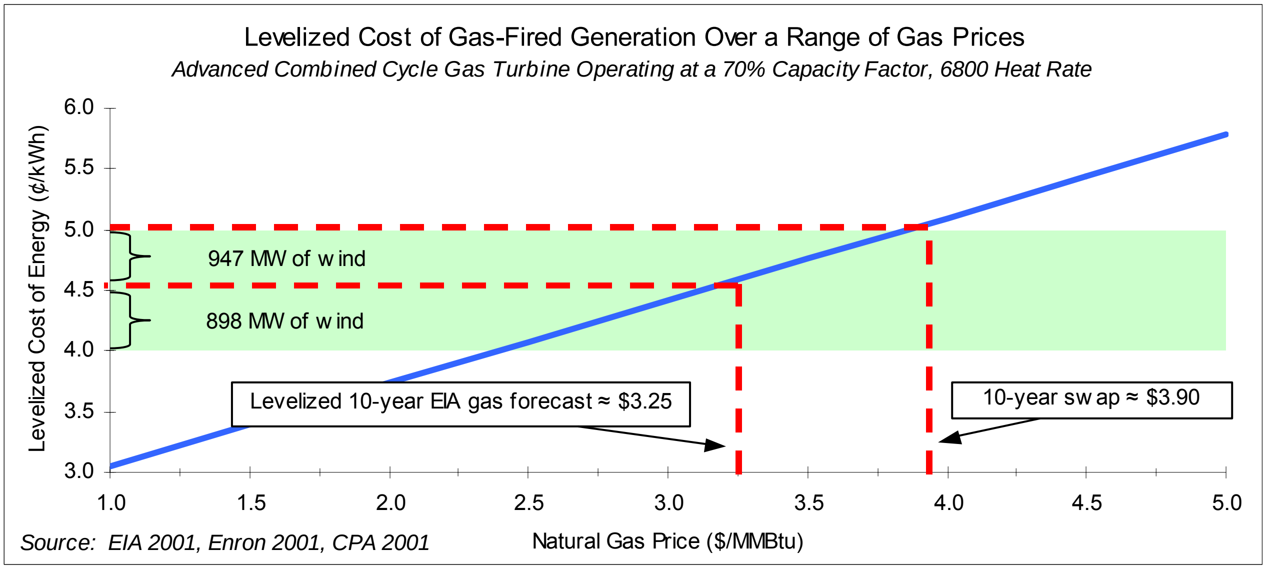

Figure 27. An Example of How a 0.5¢/kWh Premium Can Affect Resource Decisions

If the Power Authority were comparing gas-fired generation to wind power based solely on the levelized busbar cost of electricity from each, and if it assumed that gas prices would follow the path predicted by the EIA forecast, then it would have rejected all of the wind power bids that came in between 4.5-5.0¢/kWh (947 MW, or over half of the entire 1,845 MW) in favor of gas-fired generation. If instead the Power Authority used a *certain* gas price – i.e., the price of the 10-year swap – it would have accepted all 1,845 MW of wind bids. While this example is admittedly simplistic and a bit contrived (particularly since intermittent wind power is not as valuable as the dispatchable or baseload power provided by the gas plant), it nevertheless powerfully demonstrates the impact that even a small premium can have on resource decisions, and thus the importance of properly accounting for fuel price stability.

7.3 Implications

The findings of this report have important implications for utility resource planners, energy modelers and analysts, and policymakers.

7.3.1 Utility Resource Planners

Chapter 5 revealed that many utilities do in fact incorporate actual forward market prices (i.e., the price at which they could lock in gas prices) into the gas price forecasts used in their integrated resource plans. They typically do so, however, for only the first few years of what are commonly 20-year forecasts. Since the value of price stability does not disappear after a few years, further action may be warranted.

Text Box 2: Comparing the Cost of Integrating Wind with Wind's Hedge Value

A potential shortcoming of wind power is its intermittency: the power output of a wind turbine varies with wind speed, and ceases altogether in very low or high winds. Such uncontrollable fluctuations in power output may impose costs on the grid, in terms of voltage regulation and load-following services, imbalance energy payments, and reserve requirements. Just as any comparative economic evaluation of wind power should account for wind's ability to mitigate fuel price risk (as argued in this paper), so too should the real costs of integrating wind into the power system be considered. With wind power advocates typically championing wind's hedge value (along with environmental advantages) while downplaying the cost of integration, and opponents of wind typically taking the opposite stance (i.e., focusing more heavily on integration costs), the question naturally arises as to whether the cost of integrating wind outweighs its hedge value, or vice versa.

Evidence to date suggests that these two effects – one positive, the other negative – may, in fact, be *of similar magnitude*. For example, this report finds that, over the past few years at least, the hedge value of a wind plant has been on the order of 0.3-0.6¢/kWh (compared to EIA reference case gas price forecasts). Several recent wind integration studies, meanwhile, find similarly sized costs for integrating large amounts of new wind capacity into specific utility grid systems. For example, a study of Xcel Energy's service territory in Minnesota, sponsored by the Utility Wind Interest Group (UWIG), concluded that at current peak penetration levels of about 3.5% (280 MW of nameplate wind capacity on a 8,000 MW peak system), the cost of integrating wind is roughly 0.185¢/kWh (Brooks et al. 2003). A similar study of We Energies' system in Wisconsin found wind integration costs ranging from 0.19-0.29¢/kWh for 250-2000 MW of wind capacity (which at the upper bound of 2000 MW, represents a penetration rate of 28% and 51% of projected peak and average load, respectively) (Electrotek 2003). In the Pacific Northwest, PacifiCorp estimates that it would cost about 0.5-0.6¢/kWh to integrate 1,000 MW of wind power (i.e., 20% of peak load) into its system (Dragoon 2003), while Hirst (2002) estimates the cost to integrate 1,000 MW of wind power into the Bonneville Power Administration's hydro-based system to be "well under" 0.5¢/kWh. Similar studies are underway in Texas, Hawaii, and other parts of Minnesota, while studies conducted in other countries show similar results.

Of course, the study of wind integration costs is a new and evolving field of research, while the methodology used in this report to quantify wind's hedge value is also just a first step in what will undoubtedly become a more crowded field of research. Thus, the figures cited above should be considered preliminary estimates that are subject to change with further study, and that are also perhaps highly case-specific. Notwithstanding these conditions, it appears that the costs of integrating significant amounts of wind power into the grid are potentially low enough to be offset or even outweighed by the price stability benefit that wind power provides, at least based on our 3 years of data.

Assuming that long-term price stability is valued, what steps can a utility or, more generally, anyone comparing fixed-price renewable to variable-price natural gas generation, take to move towards an apples-to-apples comparison? Because of the challenges in extrapolating our findings to other forecasts, hedge durations, and time periods, we *do not* recommend blindly adding \$0.4-\$0.8/MMBtu, or 0.3-0.6¢/kWh, to any forecast, for any duration. We emphasize that these premiums were derived relative to EIA reference case gas price forecasts over a limited three-year period that may or may not represent "normal" market conditions, and for contract terms ranging from 2-10 years. Any attempt to directly apply these particular premiums outside of these parameters may be questionable, especially if better data is available at the time.

Because of the difficulty in extrapolating our results to different circumstances, below we develop process recommendations for resource planners. At least three approaches are possible:

1) **Use and extend the forward curve for natural gas:** As noted earlier, utilities have already begun to incorporate gas forward prices into their gas-price forecasts. This is a good start, but many of these utilities only rely on a year or two of forward price data. Subject to data availability, utilities (or others making resource comparisons) could extend the period over which their resource plans (or comparisons) rely on actual forward gas prices rather than uncertain price forecasts. Given the availability of NYMEX futures price data, extending the use of forward prices to at least 6 years would seem like a first step. Beyond 6 years, forward price data may be harder to come by. Where forward price data from actual contracts are not publicly available, utilities and others may have access to (or be in a position to solicit) data that are not in the public domain; broker quotes may also suffice as a way of extending the use of forward data to 10 or even 20 years. While it would be desirable to sample the forward price data as close in time as possible to when the resource plan or resource comparison is being made (for reasons explained previously in Section 6.3.2), data from Sections 4.1 and 6.3.2 imply that long-term forward markets may not be all that variable, and therefore that perfection should not become the enemy of the good.

2) **Place the onus on the generator:** As discussed in Section 2.4, natural gas-fired generators may be willing to internalize any cost of hedging (or alternatively, take on fuel price risk) and offer a long-term fixed-price electricity contract, much like renewable energy typically provides. While, as noted in Section 1.2, fixed-price renewable energy may still have some incremental "hedge value" (from placing downward pressure on gas prices, and potentially mitigating credit risk), a fixed-price gas-fired electricity contract is otherwise comparable to fixed-price renewable energy, thereby obviating the need for a utility or regulator to collect forward gas price data for the purpose of substituting into a forecast. Along these lines, utilities could follow the example of Xcel Energy in Minnesota, which – as directed by the Minnesota PUC – has worked with stakeholders to develop a method for unbiased treatment of renewable generation in its bid evaluation process. Specifically, in all-source solicitations, Xcel requires "that bidders who submit fuel-indexed or tolled fuel pricing in a proposal must also submit an otherwise identical proposal that contains fixed fuel pricing for at least 10 years." (Xcel Energy 2001) Though obtained during the solicitation rather than the planning phase, this information, along with other provisions,[83] enables Xcel to more closely approximate a true apples-to-apples comparison between renewable and other forms of generation.

[83] Other provisions include: requiring bidders who submit proposals with contract terms of greater than ten years to also submit an otherwise identical proposal with a contract length of ten years; abiding by the results of the UWIG study of wind integration costs (see Text Box 2); and including environmental externality costs in certain production cost simulation runs (Xcel Energy 2001).

3) **Adjust the forecast:** Finally, as a last resort, if forward market prices are not available over the entire planning horizon, and soliciting comparable fixed-price electricity bids from gas-fired generators is not realistic, utilities may wish to adjust forecasted gas prices upwards to account for the fact that forward prices have, potentially for reasons discussed in Chapter 6, traded above price forecasts over the past three years. While the analysis in this report suggests that an adjustment ranging from \$0.4-\$0.8/MMBtu (0.3-0.6¢/kWh at a heat rate of 7,000 Btu/kWh) is a reasonable starting point, we emphasize that these premiums were calculated with respect to EIA reference case price forecasts over the past three years, for terms ranging from 2-10 years. If using a different base gas price forecast, a higher or lower adjustment may be warranted. Likewise, this historically derived premium may well vary in the future, and may also vary with contract terms in excess of 10 years. For these reasons, the two previous approaches are preferable to this one. That said, if the two previous approaches are not possible, this approach may still be better than simply relying on forecast data, which – at least over the last three years – have been shown to be significantly below forward prices.

7.3.2 Energy Modelers and Analysts

It remains to be seen which, if any, of the explanations for empirical premiums discussed in Chapter 6 are "correct," and the implications for energy modelers and analysts vary based on the explanation under consideration. If there truly is a cost to hedging natural gas price risk with traditional instruments, and renewable energy can mitigate fuel price risk at a cost that is lower than that incurred through those traditional hedging instruments (and the market recognizes this), then the supply of renewable generation may increase at faster rate than that estimated by current national energy forecasts, leaving forecasts of renewable generation biased downwards. If instead the premiums observed in Chapter 4 are attributable to gas price forecasts that are biased downwards or are otherwise inconsistent with market expectations of future spot prices, then energy modelers will no doubt want to investigate the cause of the discrepancy between their forecasts of natural gas prices and the market's expectations of those same prices. In either case, if long-term price stability is valued, energy analysts should ideally compare the cost of renewable generation against the cost of gas-fired generation using forward gas prices as the relevant fuel cost.

7.3.3 Policymakers

While the root cause of the empirical premiums we have observed in this paper remains unclear, the fact that renewable generation provides long-term price stability is beyond reproach. As long-term price stability is undoubtedly valued to some degree by end-use customers, the "hedge value" of renewable generation should help to justify continued and new policy support for renewables. For example, if future work confirms the hedge value of renewable energy, policymakers should begin to explore practical mechanisms (such as those discussed in Section 7.3.1) 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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