Title
The Value of Renewable Energy as a Hedge Against Fuel Price Risk: Analytic Contributions from Economic and Finance Theory

Author
Bolinger, Mark A

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The Value of Renewable Energy as a Hedge Against Fuel Price Risk: Analytic Contributions from Economic and Finance Theory

Mark Bolinger and Ryan Wiser
*Lawrence Berkeley National Laboratory**

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1. Introduction

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 Energy Information Administration (EIA), natural gas-fired units account for nearly 90% of the total generating capacity added in the U.S. between 1999 and 2005 (EIA 2006b), bringing the nationwide market share of gas-fired generation to 19%. Looking ahead over the next decade, the EIA expects this trend to continue, increasing the market share of gas-fired generation to 22% by 2015 (EIA 2007a). Though these numbers are specific to the US, natural gas-fired generation is making similar advances in many other countries as well.

A large percentage of the total cost of gas-fired generation is attributable to fuel costs – i.e., natural gas prices. For example, at current spot prices of around $7/MMBtu, fuel costs account for *more than 75%* of the levelized cost of energy from a new combined cycle gas turbine, and *more than 90%* of its operating costs (EIA 2007a). Furthermore, given that gas-fired plants are often the marginal supply units that set the market-clearing price for *all* generators in a competitive wholesale market, there is a direct link between natural gas prices and wholesale electricity prices.

In this light, the dramatic increase in natural gas prices since the 1990s should be a cause for ratepayer concern. Figure 1 shows the daily price history of the "first-nearby" (i.e., closest to expiration) NYMEX natural gas futures contract (black line) at Henry Hub, along with the futures strip (i.e., the full series of futures contracts) from August 22, 2007 (red line). First-nearby prices, which closely track spot prices, have recently been trading within a $7-9/MMBtu range in the United States and, as shown by the futures strip, are expected to remain there through 2012. These price levels are $6/MMBtu higher than the $1-3/MMBtu range seen throughout most of the 1990s, demonstrating significant price escalation for natural gas in the United States over a relatively brief period.

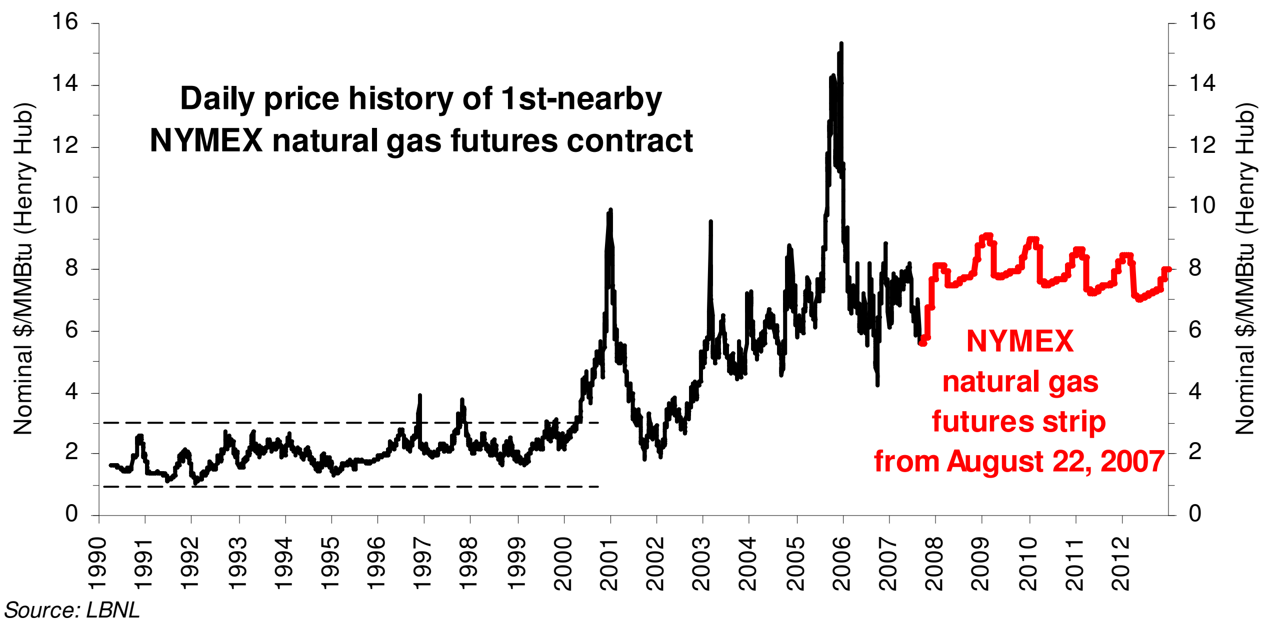

Figure 1. Historical NYMEX Natural Gas Futures Prices (First-Nearby Contract) and Current NYMEX Natural Gas Strip

Perhaps of most concern is that this dramatic price increase was largely unforeseen. Figure 2 compares the EIA's natural gas wellhead price forecast from each year's *Annual Energy Outlook* (AEO) going back to 1985 against the average US wellhead price that actually transpired. As shown, our forecasting abilities have proven rather dismal over time, as over-forecasts made in the late 1980's eventually yielded to under-forecasts that have persisted to this day. This historical experience demonstrates that little weight should be placed on any one forecast of future natural gas prices, and that a broad range of future price conditions ought to be considered in planning and investment decisions.

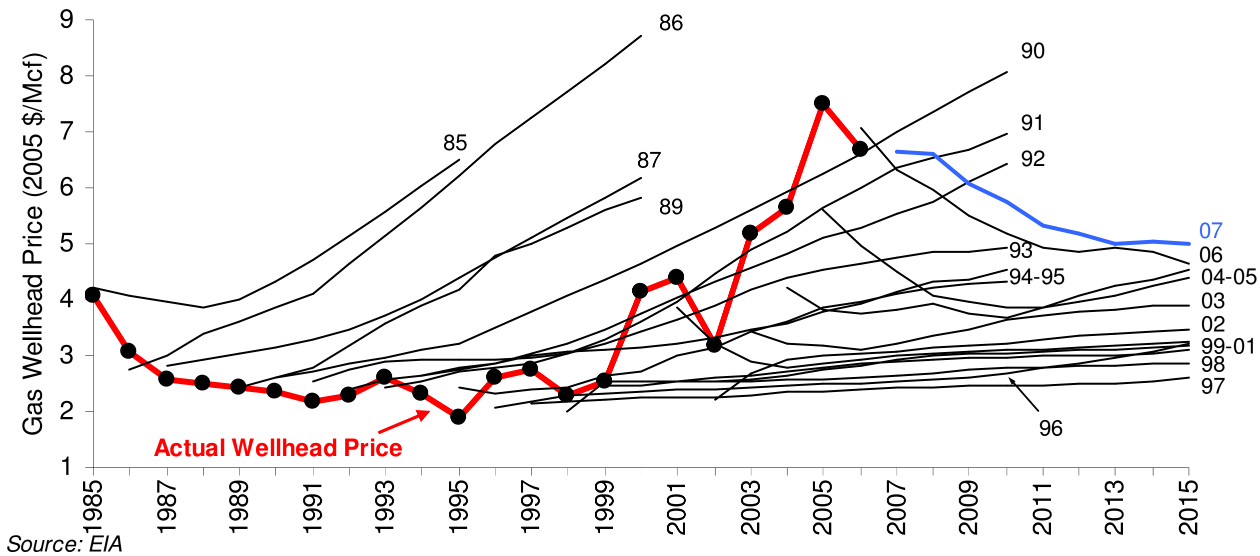

Figure 2. Historical AEO Wellhead Gas Price Forecasts vs. Actual Wellhead Price

Against this backdrop of high, volatile, and unpredictable natural gas prices, increasing the market penetration of renewable generation such as wind, solar, and geothermal power may provide economic benefits to ratepayers by displacing gas-fired generation. These benefits may manifest themselves in several ways. First, the displacement of natural gas-fired generation by increased renewable generation reduces ratepayer exposure to natural gas price risk – i.e., the risk that future gas prices (and by extension future electricity prices) may end up markedly different than expected. Second, this displacement reduces demand for natural gas among gas-fired generators, which, all else equal, will put downward pressure on natural gas prices. Lower natural gas prices in turn benefit both electric ratepayers and other end-users of natural gas.

Using analytic approaches that build upon, yet differ from, the past work of others, including Awerbuch (1993, 1994, 2003), Kahn and Stoft (1993), and Humphreys and McClain (1998), this chapter explores each of these two potential "hedging" benefits of renewable electricity.[1] Though we do not seek to judge whether these two specific benefits outweigh any incremental cost of renewable energy (relative to conventional fuels), we do seek to quantify the magnitude of these two individual benefits. We also note that these benefits are not unique to renewable electricity: other generation (or demand-side) resources whose costs are not tied to natural gas would provide similar benefits.

[1] A few other potential benefits are mentioned later in section 3.1.2. In addition to these, others include enhanced security of energy supply, and a potential reduction in wholesale power prices as low-operating-cost renewable generation displaces high-operating-cost gas-fired generation from the supply curve.

Section 2 explores the first potential hedge benefit of renewable energy – the value of the price risk mitigation provided by renewables – by comparing natural gas prices that can be locked in through long-term hedging instruments (e.g., gas futures, swaps, and fixed-price physical supply contracts) to those contained in contemporaneous government spot-price forecasts. When used to calculate the levelized cost of gas-fired generation, the former yield results that are most directly comparable to the fixed-price nature of renewable generation, but utility resource planners and policymakers nevertheless often use the latter when making resource decisions. This practice can result in apples-to-oranges comparisons – at least with respect to fuel price risk – if the two gas price streams differ in a significant and systematic fashion. Although our data are limited, we find that from November 2000 through 2006, forward gas prices for terms of 5-10 years have been considerably higher than most natural gas spot price forecasts in the United States. This implies that resource planning and modeling exercises based on these forecasts over this period have yielded results that may be biased (with respect to fuel price risk) in favor of gas-fired generation, assuming that rate stability is valued by ratepayers.

Section 3 turns to the second potential hedge benefit of renewable energy – the value of putting downward pressure on natural gas prices – by reviewing economic theory and summarizing the results of past modeling studies to determine the impact that increased renewables penetration might be expected to have on natural gas demand and prices. We also attempt to benchmark those modeling results against empirical measurements. Though results vary and uncertainty in the value of this benefit remains, current knowledge suggests that a 1% long-term reduction in demand for natural gas (whether caused by renewables or something else) in the US may, conservatively, lead to a 0.8% to 2% long-term reduction in US natural gas prices. This price reduction would be expected to flow through to *all* sectors of the economy (i.e., not just the electricity sector), resulting in significant consumer savings.

Though we use different analytic techniques, much of the analysis presented in this chapter was inspired by the work of the late Shimon Awerbuch. For example, although our approach in Section 2 does not directly depend on the applicability of modern portfolio theory or the capital asset pricing model (CAPM) to the electricity sector, the empirical results presented in Section 2 are nevertheless consistent with what one would expect from CAPM, and therefore could be used to support Shimon's more theoretical work in this area (indeed, we discuss CAPM as one potential explanation for the observed premiums). Similarly, our analysis in Section 3 is related to Shimon's later work examining the interrelationship between natural gas and oil prices. In both cases, our own work reaches the same basic conclusion that Shimon so tirelessly championed throughout his distinguished career: that renewables can reduce certain electric-sector risks, and therefore have an economically justifiable place in generating portfolios.

2. Renewable Energy Reduces Exposure to Natural Gas Price Risk

Unlike many contracts for natural gas-fired electricity generation, renewable generation is typically sold under long-term, fixed-price contracts that eliminate price risk for 15-20 years or longer.[2] Contract pricing for natural gas-fired generation, on the other hand, is often indexed to the spot price of natural gas. Assuming that electricity consumers prefer the less risky of two otherwise similar expected cash flows (or, said another way, that they prefer the cheaper of two

[2] Though our analysis and results are presented in the context of comparing renewable to gas-fired generation, they are equally applicable to comparisons of other stable-priced forms of generation (e.g., coal or nuclear power) or demand reduction (e.g., energy efficiency) to variable-price gas-fired generation.

similarly risky cash flows), a retail electricity supplier that is looking to expand its resource portfolio (or a policymaker interested in evaluating different resource options) should arguably compare the cost of fixed-price renewable generation to the *hedged* or *guaranteed* cost of natural gas-fired generation, rather than to *projected* costs based on *uncertain* spot gas price forecasts.[3] 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 (Bolinger and Wiser 2005, Bolinger et al. 2006).

This practice raises the critical question of how these two price streams – i.e., forwards and forecasts – compare. 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 spot price forecasts, then the use of such forecasts in resource acquisition, planning, and modeling exercises will arguably yield results that are either biased in favor of renewable generation (if forwards < forecasts), or biased in favor of natural gas-fired generation (if forwards > forecasts).

2.1 Methodology

We investigate the extent to which natural gas forward prices match fundamental price forecasts by comparing the prices of natural gas futures, swap, and fixed-price physical supply contracts to "reference case" gas price forecasts from the EIA. Though long-term gas price forecasts are easy to come by – e.g., the EIA forecasts are publicly available and updated every fall – long-term forward prices present a greater challenge. The NYMEX natural gas futures strip for delivery to the Henry Hub in Louisiana extends out for between five and six years (but is liquid for 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. Forward gas contracts in excess of 6 years are traded infrequently and, when traded, 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 sample to those forward prices that were traded or posted at roughly the same time as the generation of a long-term gas price forecast, to ensure an adequate comparison.

Thus, despite efforts to obtain a larger sample, our analysis is limited to comparisons based on publicly available data that we collected from November 2000-2006, and for forward price terms not exceeding 10 years. Specifically, our limited sample of natural gas forward contracts includes:

- 5- and 10-year natural gas swaps offered by Enron in early November 2000 and 2001;
- a seven-year physical gas supply contract between Williams and the California Department of Water Resources (DWR) signed in early November 2002;

[3] Note that this is strictly true only if the consumer benefit of price stability is greater than the incremental cost of achieving that stability through a hedged gas contract. Ideally, one would directly estimate the consumer *value* of a fixed-price (versus variable-price) contract. Absent such an estimate, here we instead focus on the *cost* of achieving such a fixed-price gas contract. Moreover, although this chapter focuses exclusively on fuel price risk, the cost of fuel (and its impact on total generation costs) is only one of many important considerations involved in any resource comparison. For example, the relative dispatchability of generating resources – regardless of levelized costs – may be of prime importance in some instances.

- the 72-month NYMEX natural gas futures strip (averaged each calendar year) from November 2002, October 2003, and October 2004;
- the 60-month NYMEX natural gas futures strip from November 2005 and 2006.

In each case, we evaluate these forward prices against the EIA's then-current reference case forecast of spot natural gas prices delivered to electricity generators (in nominal dollars[4]), which is generated in the fall of each year and presented in the AEO released towards the end of the year. We adjust the locational basis of the EIA's forecast to match the stated delivery point of the forward gas price being compared.[5] Although the use of EIA reference case gas price forecasts for this purpose is somewhat controversial (as discussed later), we use them nonetheless because they are publicly available, have been widely vetted, and most importantly are commonly adopted by the EIA and others as a "base case" price scenario in policy evaluations, modeling exercises, and even resource acquisition decisions.

2.2 Empirical Findings of a Premium

Each of these comparisons reveals that forward natural gas prices have traded above EIA reference case price forecasts during this seven-year period, sometimes significantly so. Figure 3 consolidates the resulting levelized 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.[6] As shown, the magnitude of the empirically derived premiums varies somewhat from year to year, contract to contract, and by contract term, ranging from $0.5-$2.4/MMBtu, or 0.4-1.7¢/kWh assuming a highly-efficient gas-fired power plant.

[4] Unless otherwise noted, 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 EIA gas price forecasts – which are expressed in real terms – to nominal terms using the EIA's own inflation projections.

[5] For details on the specific basis adjustments, see Bolinger et al. (2003).

[6] We derived the premiums by levelizing the first 5, 6, 7, and 10 years of the EIA forecasts (using a nominal discount rate of 10%) and subtracting the resulting levelized forecast price from the corresponding forward prices. Because in this case 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. For example, using a discount rate of 5% barely changed the results.

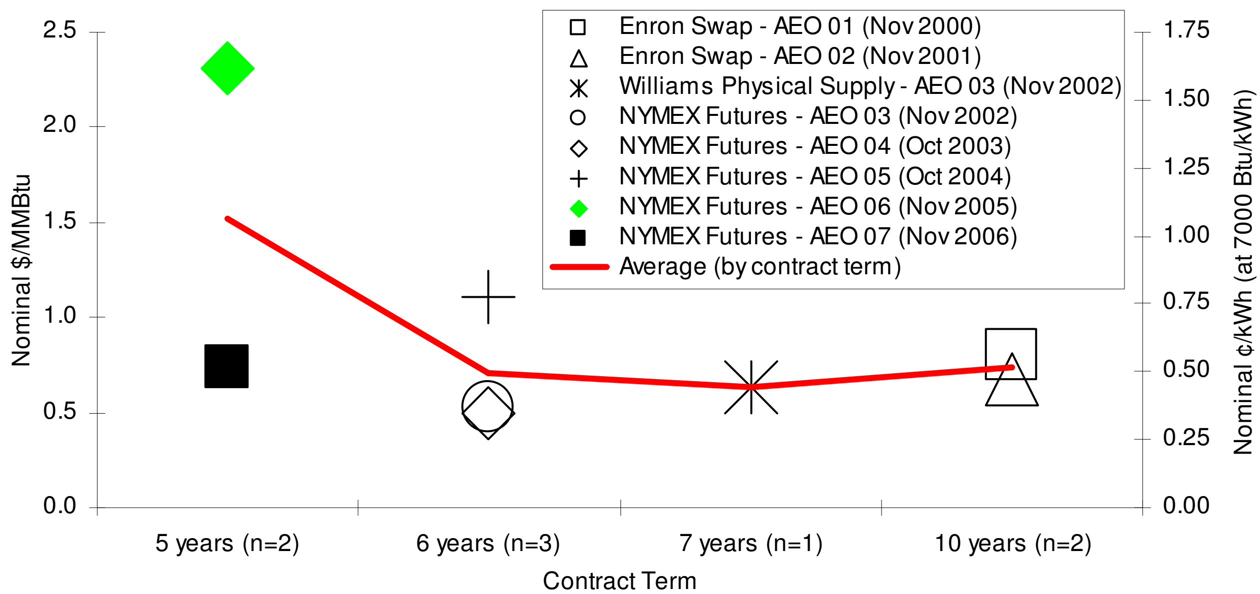

Figure 3. Levelized Premiums (Forwards – Forecasts)

Though the relatively tight range of premiums (November 2005 excepted) is somewhat remarkable, the limitations in our data sample mean that one cannot easily extrapolate these findings beyond the seven periods for which we have data, or to contract terms longer than those examined (10 years). It is, however, at least apparent that utilities and others who have conducted resource planning and modeling studies based on EIA reference case gas price forecasts from November 2000-2006 have produced results that, by seemingly ignoring fuel price risk, favor variable-price gas-fired over fixed-price renewable generation (at least over the 5- to 10-year terms of the comparisons presented in Figure 3).

The EIA's forecasts are by no means the only long-term gas price forecasts available to and used by market participants. In order to assess how the premiums presented in Figure 3 would change had we compared natural gas forward prices to some forecast other than the EIA's, we reviewed a number of other long-term gas price forecasts, sourced from the EIA's own forecast comparisons (contained in each year's AEO), as well as from various utility integrated resource plans. As shown in Bolinger et al. (2003), with few exceptions, the EIA reference case forecast has generally been higher – and often substantially so – than most other forecasts generated from 2000-2003 and used by utilities and others. A more recent examination of AEO forecast comparisons reveals that this trend has generally continued since 2003 (EIA 2004, 2005, 2006a), with the notable exception of the AEO 2007 reference case forecast, which is in some cases significantly below the other long-term forecasts highlighted in the forecast comparisons (EIA 2007a). But in general, these findings suggest that some of the premiums presented in Figure 3 would be *even larger* when comparing forward prices to some of the other commonly used gas price forecasts.

2.3 Potential Explanations for Empirical Premiums

The differences between natural gas forward prices and spot gas price forecasts revealed in the previous section, and the implications such differences hold for resource comparisons, are significant. We are keenly aware, however, that these empirical results are based on limited historical data over a 7-year period characterized by extreme price volatility. In considering whether it is possible to extrapolate our findings, or the implications thereof, into the future, it is important to try to understand some of the causes of our empirical findings.

Two possible explanations may partially or wholly account for the sizable differences between our limited samples of observed natural gas forwards and forecasts: (1) the forecasts are out of tune with market expectations, so the observed empirical premiums reflect forecast bias; and (2) hedging is not costless, and the observed premiums represent the cost of hedging.[7] Below we assess each of these possibilities.[8]

2.3.1 The Forecasts May Be Out of Tune with Market Expectations

One possible explanation for our empirically derived premiums between gas forwards and forecasts is related to the forecasts themselves, which may have been biased downwards or otherwise inconsistent with broader market expectations of future spot gas prices from November 2000-2006.

Although this explanation cannot be directly supported (or refuted) by our empirical observations, it has gained some traction in the literature. For example, Considine and Clemente (2007) use error decomposition analysis on AEO natural gas price forecasts to identify the proportion of the forecast error that is attributable to either randomness, bias, or the forecasting model (i.e., the EIA's National Energy Modeling System, or NEMS). Over the period from 1998-2006, they find that between 56% and 87% of the forecast errors were attributable to systematic bias, on average (with the range reflecting different forecast periods, from 1 to 4 years ahead). In other words, forecast bias could explain a significant portion of the empirical premiums presented earlier in Figure 3.

Two considerations potentially call into question the widespread applicability of Considine and Clemente's (2007) results, however. First, given the relatively short-term (i.e., one-to-four years) of the forecasts analyzed, the EIA's *Short-Term Energy Outlook* forecasts (which are *not* generated using NEMS) would arguably have been more suitable for analysis than the AEO forecasts, which are longer-term in nature. Second, a visual inspection of Figure 2 from earlier shows that the sample period chosen – from 1998-2006 – is perhaps itself biased, in that it falls exclusively within the recent period of apparent under-forecasts that began in the mid-1990s (as opposed to the earlier period of over-forecasts that occurred in the 1980s). Thus, while systematic bias may indeed be a problem over the period from 1998-2006 – which, it should be noted, also includes our sample period – these results are somewhat selective.

Another potential problem with our exclusive use of the EIA's AEO forecasts as the point of comparison is that, by definition, the EIA's "reference case" forecast may not represent the market's view of future spot gas prices. For example, the EIA itself 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 the "most likely " outcome.[9] In

[7] Another *possible* explanation for our findings is simply that our analysis is plagued by data issues that prohibit a meaningful comparison between natural gas forward prices and price forecasts. It is possible, for example, that the forward prices are upwardly biased. Or, even if the forward price and price forecast are unbiased, it is possible that 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. Both of these possibilities are examined at length in Bolinger et al. (2003), however, and are found to be inconsequential.

[8] More detailed information on these potential explanations is provided in Bolinger et al. (2003).

[9] Although the EIA apparently does not hold this view about its own forecasts, some have 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

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 "reference case" or even "low economic growth case" forecast, for example. Furthermore, by assuming away weather and inventory variability, and possible changes in 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*.[10]

Though 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 adopt 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. Furthermore, Bolinger et al. (2003) and Bolinger and Wiser (2005) demonstrate that some utilities – one important segment of the energy 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, if forecast bias is an issue, it is not restricted to the EIA reference case forecast: as noted earlier, other private sector gas price forecasts have often been *even lower than* the EIA's reference case forecast.

2.3.2 Hedging May Not Be Costless

A second potential explanation for the difference between forward and forecast gas prices is that hedging may not be costless – i.e., forward prices may be (for several reasons) biased predictors of future spot prices. This notion has been extensively debated in the literature ever since Keynes first introduced the idea of *normal backwardation* in his 1930 *Treatise on Money*. Specifically, Keynes (1930) argued that *hedgers* who use futures markets to mitigate commodity price risk must compensate *speculators* for the "insurance" that they provide.[11] A futures market that is dominated by "short hedgers" – i.e., a market with more natural sellers than buyers of future contracts – results in what is known as *positive net hedging pressure*, and requires

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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. Though, again, this argument apparently does not hold for the EIA reference case forecast, its implications are nonetheless worth noting. Specifically, since gas prices are generally believed to be lognormally distributed (i.e., positively skewed), the mean must lie above the mode, meaning that true market expectations must be higher than reference case gas-price forecasts (if those forecasts do indeed 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 (though, once again, note that the EIA does not consider its reference case forecast to be a mode). More importantly, however, this argument calls into question why utilities and others would ever place significant emphasis on the use of 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 (which, by definition, must be a mean estimate), thereby erroneously making gas-fired generation appear to be cheaper than the market expects it to be on average.

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

[11] *Hedgers* can be thought of as commodity producers (e.g., natural gas drillers) or consumers (e.g., electric utilities) who have a natural underlying position in a commodity that can be hedged by selling or buying futures contracts. A "short" hedge transaction is one in which the hedger currently owns the underlying commodity and will be selling it in the future, and so today sells futures contracts to lock in the future sales price of the commodity and thereby secure a profit margin. Conversely, a "long" hedge transaction is one in which the hedger does not currently own the commodity but will be buying it in the future, and so today buys futures contracts to lock in the future purchase price of the commodity and thereby secure a profit margin. In contrast to hedgers, *speculators* have no natural underlying position in the commodity, and trade in the futures market purely to make a profit. If a short hedger cannot find a long hedger to trade with, a speculator will step in to buy the short hedger's futures contracts, in the hopes of being able to re-sell them at a profit. In this way, speculators provide liquidity to the market.

speculators to step in and purchase the excess futures contracts that are for sale in order to clear the market. To entice speculators to provide this "insurance" or liquidity, short hedgers must, according to Keynes, be willing to sell futures contracts to speculators at prices that are *lower* than the expected spot price, thereby enabling speculators to earn a positive return simply by buying the contracts and holding them to expiration (when spot and futures prices presumably converge). The opposite occurs in a market dominated by long hedgers, resulting in *negative net hedging pressure*: to clear the market, speculators must *sell* futures contracts, and are compensated in the form of futures prices that are *higher* than the expected spot price, again enabling them to earn a positive return simply by holding the short position to expiration.

Over the years, a number of studies have attempted – with mixed results – to empirically confirm or refute the existence of such "risk premiums" in the futures prices of a variety of commodities by examining the returns to speculators. Much of this work has been based on a strict application of Keynes' theory, which, among other things, assumes that hedgers – characterized mainly as producers who are natural short hedgers – will be net short futures and that speculators will therefore be net long futures. 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., in aggregate, short hedges may not always outnumber long hedges). Though results remain inconclusive, the relaxation of the assumption that speculators are always 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, depending on whether net hedging pressure is negative or positive, respectively) embedded in futures prices.

Still other researchers have searched for risk premiums in commodity futures prices from within the framework of the Capital Asset Pricing Model (CAPM). Under CAPM (described in more detail later), it is not the variability of prices per se, but rather the correlation of price variability with changes in total wealth, that determines the risk of the underlying asset. Dusak (1973) examined wheat, corn, and soybean futures within the CAPM framework, and found no evidence of either non-zero systematic risk or non-zero futures returns.[12] Hirshleifer (1988), meanwhile, developed a model whereby the risk premium consists of two terms – a systematic risk term (i.e., related to CAPM) and a term due solely to residual risk (i.e., related to net hedging pressure).

Below we examine the possibility that either net hedging pressure or CAPM-related systematic price risk is responsible for the empirical premiums observed in the natural gas market from November 2000-2006, as presented earlier in Figure 3.[13]

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[12] Note that these findings do not rule out CAPM as a potentially useful tool for this purpose, since under CAPM, one would expect zero systematic risk to lead to no risk premium.

[13] Though not discussed here, those hedging gas price risk may also incur incremental costs relative to market expectations of future spot prices simply due to the presence of transaction costs. In commodity 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 will either rise or fall while one is trying to buy or sell, respectively), one must typically "cross" the bid-offer spread (i.e., pay the offer 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). In liquid markets, bid-offer spreads are typically very small, and of little concern. In less-liquid markets, however, bid-offer spreads can be quite wide, and can have a more significant impact on the cost of transactions. Bolinger et al. (2003) illustrate that while bid-offer spreads in the NYMEX natural gas futures market are quite small in the front months due to high liquidity, they widen dramatically as liquidity declines along the strip. In fact, beyond 36-48 months, there is not necessarily "a market" per se, and the cost of executing a deal of any size may depend largely on the ability to locate a willing

Net Hedging Pressure in the Natural Gas Market

To test whether the positive premiums (natural gas forward prices that are higher than contemporaneous forecasts of spot prices) observed earlier could be the direct result of negative net hedging pressure, Figure 4 depicts net hedging pressure in the natural gas market from 2000 through 2006.[14] Net hedging pressure has been largely positive over this period, suggesting that futures prices should generally be *lower* than expected spot prices, though it has clearly varied quite a bit, and has been negative at times. In fact, during three of the seven periods in which we sampled forward prices (dates indicated by shaded vertical lines), net hedging pressure was either neutral or slightly negative, suggesting that futures prices should, at least in those instances, match or be higher than expected spot prices. Nonetheless, because Figure 4 does not show systematic negative net hedging pressure over the period of our analysis, it does not support the idea that negative net hedging pressure is directly responsible for the positive premiums observed earlier. In fact, if anything, the generally-positive net hedging pressure presented in the figure suggests that forward natural gas prices should be lower than expected spot prices, directly contradicting the results presented earlier and clearly demonstrating that net hedging pressure is an unlikely explanation for our earlier findings.

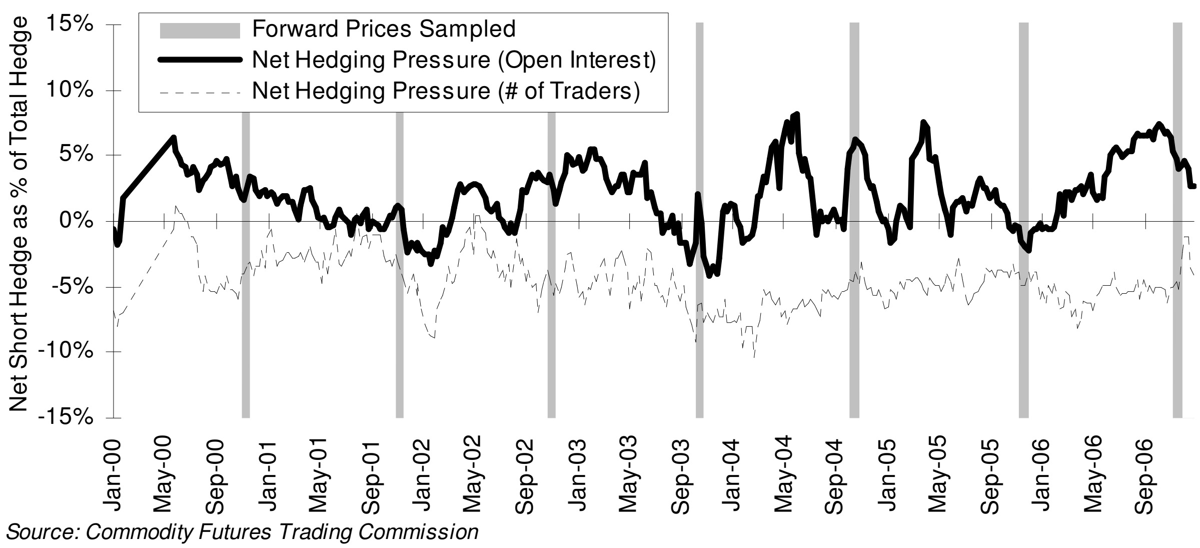

Figure 4. Net Hedging Pressure in the Natural Gas Futures Market, 2000-2006

buyer or seller, which may in turn require significant price concessions at times. In other words, even if futures prices perfectly match market price expectations, those seeking to hedge price risk for lengthy terms may still be required to pay a sizable premium, in the form of transaction costs, in order to execute the hedge.

[14] The data come 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. Net hedging pressure is defined as the difference between the number of outstanding short and long contracts divided by the sum of outstanding short and long contracts (among commercial traders). Commercial traders (i.e., hedgers) currently account for about 50% of the open interest in the natural gas futures market – down sharply from roughly 80% earlier in this decade. The correspondingly sharp increase in the open interest of speculators over the past few years potentially calls into question the continued relevance of commercial net hedging pressure as an indicator of the direction of futures premiums.

Systematic Risk in Natural Gas Prices

Setting aside net hedging pressure and the returns of speculators, what if natural gas producers benefited from price volatility, while natural gas consumers were hurt by it? In this case, producers would require compensation (i.e., a premium) for being locked into long-term fixed-price contracts, and consumers would be willing to pay such compensation. Economic theory provides some support for this very scenario in the form of the Capital Asset Pricing Model (CAPM).[15]

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

In this specific case, where gas with a negative beta is risky to consumers and beneficial to producers, consumers have an incentive to hedge natural gas price risk, while producers do not. Intuitively, it follows that even if both consumers and producers share identical expectations of future spot gas prices, producers will still require – and consumers will be willing to pay – a premium over expected spot prices in order to lock in those prices today. 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 a positive premium embedded in forward prices.

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). More recently, Bolinger et al. (2003) regressed annual changes in the price of gas delivered to electricity generators against annual S&P 500 returns, and found a natural gas beta of -0.1 from 1980 through 2002; a 2007 update to that regression yields a beta of -0.2 through 2006 (with a 90% confidence interval ranging from -0.8 to +0.3). Both of these more-recent estimates are lower in magnitude than

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

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

those from the 1990s, and could reflect a number of factors, including: use of different price series (e.g., the price of gas delivered to electric generators versus wellhead prices), use of average-annual versus year-end prices, different sampling periods, or even potential changes in the relationship between fuel prices and the economy.

It is also possible to back into empirical (rather than regression-based) estimates of the beta of natural gas, by using our sample of forward prices and EIA reference case gas price forecasts. These are the specific betas that would be required to fully explain our empirically derived discrepancy between natural gas forward and forecast prices within the context of CAPM. 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 in one direction or the other). One then calculates the present value of both price streams – the forward market price stream using the known "riskless" discount rate (i.e., the US Treasury 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 expected out-performance of risky assets (stocks) over riskless assets (Treasuries) – to yield the estimated beta.[17]

Performing this exercise using our sample of forward market prices and EIA reference case forecasts, and an assumed market risk premium of 5%,[18] we arrive at the various estimates of beta presented in Figure 5. These empirical estimates of beta are generally consistent in sign and magnitude with the regression-based estimates from the 1990s literature presented above, though the more-recent regression-based estimates are less-negative than the implied betas shown in Figure 5 . Nonetheless, the consistency in the negative sign of these beta estimates at least suggests that CAPM may partially explain why long-term natural gas forwards have been priced higher than contemporaneous EIA price forecasts from 2000-2006.

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

[18] Although the market risk premium has traditionally been estimated based on the long-term historical out-performance of stocks over Treasuries, many analysts think that this backward-looking approach yields a risk premium that is too high (in excess of 6%) and will likely not persist into the future. Though there is considerable debate about the appropriate size of a forward-looking risk premium, estimates in the range of 0%-5% can be found. Here we simply use 5% across the board, so as to acknowledge the concerns of analysts yet at the same time not stray too far from historical estimates. We note that only the magnitude – and not the sign – of the implied beta will change as different estimated market risk premiums are used.

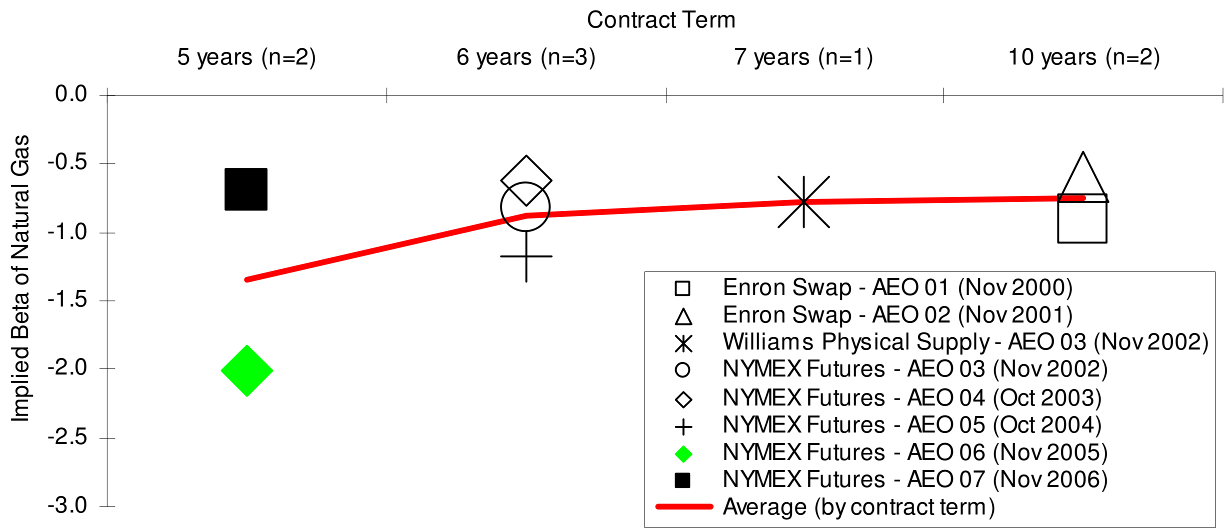

Figure 5. Implied Beta of Natural Gas, by Contract Term

As theoretically appealing as CAPM may be, however, we are nevertheless hesitant to place too much faith in it as the sole explanation for our empirical findings, for several reasons. First, 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 financial 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 stock market. Second, if CAPM were the dominant influence, then one would expect past studies of the efficiency of the natural gas futures market to regularly demonstrate a systematic positive difference between futures and realized spot prices. As discussed in Bolinger et al. (2006), this is not the case: some, but not all, of these studies do show evidence of a premium, but in some cases the sign of the premium varies with net hedging pressure, rather than always being positive as would be required under CAPM with a negative beta. Finally, recent regression-based estimates of Beta as provided in Bolinger et al. (2003) and updated earlier in this chapter are seemingly not consistent in magnitude with the negative betas that would be required to fully explain the observed forward-forecast premiums presented earlier. Thus, while CAPM may be a contributor towards natural gas futures prices that are in excess of expected spot prices, other factors seem likely to be at work as well.

2.4 Implications

Unfortunately, neither of the potential explanations presented above is either fully satisfying or easily refutable, though there is some evidence that biased forecasts and the CAPM may play some role in the forward-forecast premiums observed earlier. Regardless of the explanation, however, the basic implication of our study for renewable energy (or any other energy source that is immune to natural gas fuel price risk) remains the same: *one should not blindly rely on gas price forecasts when comparing the levelized costs of fixed-price renewable to variable-price gas-fired generation contracts.* These forecasts do not inherently allow one to assess the value of renewable energy in hedging uncertain gas prices. 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 true market expectations, then one clearly would not want to use them as the sole basis for investment decisions or resource comparisons.

A better way of comparing the levelized costs of renewable and gas-fired generation would, arguably, be to use forward natural gas price data as opposed to natural gas price forecasts. In other words, if consumers value price stability (and if the benefits of stability exceed the incremental cost of achieving it through natural gas forwards), then the cost of fixed-price renewable generation should be compared to the *hedged* or *guaranteed* cost of natural gas-fired generation, rather than to *projected* costs based on *uncertain* gas price forecasts. Such a comparison, over the last seven years at least, would have found an additional hedging benefit of renewable generation that would not have been accounted for if uncertain gas price forecasts were used.

Of course, our findings cannot be easily extrapolated beyond the 5- to 10-year terms analyzed here (i.e., we can not know whether the observed premiums persisted over longer terms), and publicly available forward price information is unlikely to extend beyond these terms regardless. These shortcomings call into question the practicality of implementing our recommendation to use forwards instead of forecasts in resource comparisons. Though we acknowledge that implementation is a challenge, several options, including soliciting information on long-dated forward prices or blending existing forward prices into long-term fundamental forecasts, are arguably superior to doing nothing. These and other implementation issues are discussed further in Bolinger et al (2003).

3. Renewable Energy Reduces Natural Gas Prices

The previous section explored the notion that, by displacing natural gas-fired generation, fixed-price renewable generation directly reduces natural gas price risk, providing a benefit to consumers (if not society at large). This section explores a more indirect and subtle – but no less important – consequence of that same displacement: a reduction in demand for natural gas among gas-fired generators will – all else equal –place downward pressure on natural gas prices for all gas consumers. Many recent modeling studies of increased renewable energy deployment in the United States have demonstrated that this "secondary" effect of putting downward pressure on natural gas prices could be significant, with the consumer benefits from reduced gas prices in many cases more-than-offsetting any increase in electricity costs caused by renewables deployment.[19] As a result, this price-suppression effect is increasingly cited as justification for policies promoting renewable generation.[20]

[19] Awerbuch and Sauter (2005) go one step further and, due to the correlation between natural gas and oil prices, make the case that displacement of gas-fired generation may also reduce oil prices.

[20] Although we emphasize the impact of renewable generation on natural gas prices, we acknowledge that similar effects would result from greater energy efficiency, as well as increased utilization of other non-gas energy sources whose fuel costs are not highly correlated with the price of natural gas (e.g., coal or nuclear power). Additionally, while our analysis focuses on the US, similar effects might be expected elsewhere.

3.1. A Cursory Review of Economic Theory

3.1.1 Natural Gas Supply and Demand Curves

Economic theory predicts that a reduction in natural gas demand caused by increased deployment of renewable energy will – by causing an inward shift in the aggregate demand curve for natural gas – generally lead to a reduction in the price of natural gas relative to the price that would have been expected under business-as-usual conditions.[21] The magnitude of the price reduction will depend on the amount of demand reduction, with greater displacement of demand for gas leading to greater drops in the price of the commodity.[22] Equally important, the shape of the natural gas supply curve will have a sizable impact on the magnitude of the price reduction. The more upwardly-sloped the supply curve, the greater the price reduction will be.

The shape of the supply curve for natural gas will, in turn, depend on whether one considers short- or long-term effects. One generally assumes upward, steeply sloping supply curves in the short term when supply constraints exist in the form of fixed inputs like labor, machinery, and well capacity (Henning, Sloan & de Leon 2003). In the long term, however, the supply curve will presumably flatten because supply will have time to adjust to higher (or lower) demand expectations, for example, through increased (or decreased) exploration and drilling expenditures (Dahl & Duggan 1998).[23] Therefore, for each unit of gas displacement, a higher price-reduction effect is to be expected in the short term than in the long term.[24]

Here we are primarily interested in the long-term impacts of renewable energy investments in the US as a whole, and thus focus most of our attention on the shape of the long-term supply curve. We take this approach for two key reasons. First, renewable energy investments are typically long-term in nature, so their most enduring effects are likely to occur over the long term. Second, the model results reviewed here often do not clearly distinguish between short-term and long-term effects, but appear to focus predominantly on long-term, national-level impacts.

3.1.2 Social Benefits, Consumer Benefits, and Wealth Transfers

We have made the case that increased deployment of renewable energy can and should lower the price of natural gas relative to a business-as-usual trajectory. This price reduction will benefit consumers by reducing the price of gas delivered to electricity generators (assumed to be passed through in the form of lower electricity prices), and by reducing the price of gas delivered for direct use in the residential, commercial, industrial, and transportation sectors. Before proceeding, however, it is important to address the nature of this "benefit," because

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[21] It is worthy of note that natural gas prices may fall over time even with increasing demand if technological progress allows gas to be extracted at lower prices despite the need to extract resources from increasingly less attractive resource areas. Our argument here is simply that a reduction in natural gas demand is expected, *all else being equal*, to result in lower natural gas prices than would be seen under a higher-demand scenario.

[22] We would not generally expect any particular threshold of demand reduction to be required to lower the price of gas (unless the supply curve was flat over some of its range). Instead, greater quantities of gas savings should result in higher levels of price reduction. The impact on prices, however, need not be linear over the full range of demand reductions; it will, instead, depend on the exact – as yet unknown – shape of the supply curve in the region in which it intersects the demand curve.

[23] Because natural gas is a non-renewable commodity, however, the long-term supply curve must eventually slope upward as the least-expensive resources are exhausted.

[24] Note that the long-term *demand* curve is also expected to be flatter than the short-term *demand* curve (EMF 2003). This too will moderate the long-term impacts of renewable energy investments on natural gas prices.

mischaracterizations are common and may lead to unrealistic expectations and policy prescriptions.

In particular, according to economic theory, lower natural gas prices that result from an inward shift in the demand curve do not necessarily lead to a complete gain in economic welfare, but may instead represent – to some degree at least – a shift of resources (i.e., a transfer payment) from natural gas producers to natural gas consumers. As natural gas producers see their profit margins decline (a loss of producer surplus), natural gas consumers benefit through lower gas bills (a gain of consumer surplus). Wealth transfers of this type are not a standard, primary justification for policy intervention on economic grounds.

Reducing gas prices may still be of importance in policy circles, however, where it may be viewed as a positive ancillary effect of renewable energy deployment. Energy programs are frequently assessed using consumer impacts as a key metric. Furthermore, the wealth redistribution effect may, in fact, result in a social welfare gain if economy-wide macroeconomic adjustment costs are expected to be severe in the case of natural gas price spikes and escalation. Such adjustment costs have been found to be significant in the case of oil price shocks and one might expect to discover a similar effect for natural gas, though research has not yet targeted this issue.[25] Moreover, if producers are located outside of the country in question – an increasingly likely situation in the US as the country becomes more reliant on imports of natural gas [especially liquefied natural gas (LNG)] – the wealth redistribution would increase aggregate domestic welfare. Finally, because reduced natural gas demand allows society to postpone more-expensive natural gas exploration and drilling expenses, some fraction of the gain from lower gas prices may be considered a social benefit.

3.2 Review of Previous Studies

A number of recent studies of renewable energy policies have estimated the impact of increased deployment of renewable energy on natural gas prices in the US These studies have exclusively evaluated a *renewables portfolio standard* (RPS) – a policy that requires electricity suppliers to source an increasing percentage of their supply from renewable generation over time. In most cases, national-level policies have been the focus of attention, but state- or regional-level policies have also been evaluated.

We compiled and evaluated information from 13 such studies: (1) six studies by the Energy Information Administration focusing on US national RPS policies, two of which model multiple RPS scenarios; (2) six studies of national RPS policies by the Union of Concerned Scientists (UCS), three of which model multiple RPS scenarios; and (3) one study by the Tellus Institute that evaluates three different standards of a state-level RPS in Rhode Island (combined with RPS policies in Massachusetts and Connecticut).[26] All relevant studies for which we were able to obtain comprehensive data were included.

[25] Although the literature on the macroeconomic impacts of oil-price escalation is broad, we are aware of no research that has explored the impact of natural gas price escalation. Extrapolating from studies that have looked at oil-price shocks, Brown (2003) estimates that a sustained doubling of natural gas prices might reduce US gross domestic product (GDP) by 0.6-2.1% below what it otherwise would be.

[26] In some instances, the studies included in our analysis actually incorporated multiple sensitivity cases in addition to different RPS standard levels (e.g., different cost caps or policy sunset provisions). In these instances, we selected just one of the sensitivity cases to report here.

Each of the studies reviewed here relies on the EIA's National Energy Modeling System (NEMS), which is a national integrated general equilibrium energy model.[27] NEMS does not exogenously define a simple, transparent, long-term natural gas supply curve; instead, a variety of modeling assumptions and inputs are made that, when combined, implicitly define the long-term supply curve. For this reason, we must evaluate the long-term impact of increased renewable energy deployment on natural gas prices in an implicit fashion – i.e., by reviewing modeling results.

3.2.1 National Gas Consumption and Price Impacts

Table 1 summarizes some of the key results of these studies.[28] As shown, some of the studies predict that increased renewable generation will modestly increase retail electricity prices on a national average basis, though more recent studies have sometimes found small price reductions (due to improved renewable energy economics relative to gas-fired generation). Increased renewable generation also causes a reduction in US natural gas consumption, ranging from less than 1% to nearly 11% depending on the study. This reduced gas consumption suppresses natural gas prices, with expected price reductions ranging from virtually no change in theUS average wellhead price to an 18% reduction in that price.[29]

These wellhead price reductions translate into lower gas bills for natural gas consumers and, by reducing the price of gas delivered to the electricity sector, moderate the expected renewable-energy-induced increase in electricity prices predicted by many of the studies. Though not shown here, Wiser et al. (2005) demonstrate that the absolute reduction in delivered natural gas prices for the electricity and non-electricity sectors largely mirrors the reduction in wellhead gas prices shown in Table 1. This suggests that changes in wellhead prices flow through to delivered prices for all US consumers – even those consumers located in regions that do not experience significant renewable energy development – on an approximate one-for-one basis.

Figure 6 graphically presents the expected impact of increased renewable generation on the displacement of US gas consumption in 2020 (relative to the "base-case" forecast) among the 13 studies in our sample. Figure 7, meanwhile, shows the expected impact of increased renewable generation on the average wellhead price of natural gas in the United States. As expected, increased levels of renewable energy deployment generally lead to higher levels of gas displacement and greater price reductions. Variations in the level of gas displacement and wellhead price reductions are also caused by different assumptions for the degree to which

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[27] Because NEMS is revised annually and many of these studies were conducted in different years, they used different versions of NEMS. In addition, some of the studies used modified versions of NEMS with, for example, different renewable energy potential and cost assumptions.

[28] Table 1 presents the projected impacts of increased renewable energy deployment in each study relative to some baseline. The baselines differ from study to study, which partially explains why, for example, a 10% RPS in two studies can lead to different impacts on renewable generation (in TWh and in % increase in renewable generation, above the baseline). The impact on renewable generation also varies because of assumed cost caps used in some studies or sunset provisions that in some studies terminate the RPS in a certain year, leading to fewer modeled renewable capacity additions in later years of the study because there are fewer years under the RPS in which to recoup investment costs. Additional variations among model runs include renewable technology and cost assumptions and the treatment of the federal production tax credit for wind power.

[29] Note that NEMS captures the secondary or "rebound" effects of reduced prices on natural gas consumption and exploration (i.e., lower prices cause demand to rebound somewhat, and gas exploration and drilling to drop). The modeling results presented here represent projected impacts after such rebound effects have taken place.

renewable energy offsets natural gas generation (versus other forms of generation), and the shape of the natural gas supply curve.

Table 1. Summary of Results from Past Renewable Energy Deployment Studies

Author	RPS	Increase in US Renewable Generation TWh (% of total generation)	Reduction in US Gas Consumption Quads (%)	Gas Wellhead Price Reduction $/MMBtu (%)	Retail Electric Price Increase Cents/kWh (%)
EIA (1998)	10%-2010 (US)	336 (6.7%)	1.12 (3.4%)	0.34 (12.9%)	0.21 (3.6%)
EIA (1999)	7.5%-2020 (US)	186 (3.7%)	0.41 (1.3%)	0.19 (6.6%)	0.10 (1.7%)
EIA (2001b)	10%-2020 (US)	335 (6.7%)	1.45 (4.0%)	0.27 (8.4%)	0.01 (0.2%)
EIA (2001b)	20%-2020 (US)	800 (16.0%)	3.89 (10.8%)	0.56 (17.4%)	0.27 (4.3%)
EIA (2002a)	10%-2020 (US)	256 (5.1%)	0.72 (2.1%)	0.12 (3.7%)	0.09 (1.4%)
EIA (2002a)	20%-2020 (US)	372 (7.4%)	1.32 (3.8%)	0.22 (6.7%)	0.19 (2.9%)
EIA (2003b)	10%-2020 (US)	135 (2.7%)	0.48 (1.4%)	0.00 (0.0%)	0.04 (0.6%)
EIA (2007b)	15%-2020 (US)	242 (5.1%)	0.35 (1.3%)	0.08 (1.7%)	0.10 (1.4%)
UCS (2002a)	10%-2020 (US)	355 (7.1%)	1.28 (3.6%)	0.32 (10.4%)	-0.18 (-2.9%)
UCS (2002a)	20%-2020 (US)	836 (16.7%)	3.21 (9.0%)	0.55 (17.9%)	0.19 (3.0%)
UCS (2002b)	10%-2020 (US)	165 (3.3%)	0.72 (2.1%)	0.05 (1.5%)	-0.07 (-1.1%)
UCS (2003)	10%-2020 (US)	185 (3.7%)	0.10 (0.3%)	0.14 (3.2%)	-0.14 (-2.0%)
UCS (2004a)	10%-2020 (US)	181 (3.6%)	0.49 (1.6%)	0.12 (3.1%)	-0.12 (-1.8%)
UCS (2004a)	20%-2020 (US)	653 (13.0%)	1.80 (5.8%)	0.07 (1.9%)	0.09 (1.3%)
UCS (2004b)	10%-2020 (US)	277 (5.5%)	0.62 (2.0%)	0.11 (2.6%)	-0.16 (-2.4%)
UCS (2004b)	20%-2020 (US)	647 (12.9%)	1.45 (4.7%)	0.27 (6.7%)	-0.19 (-2.9%)
UCS (2007)	20%-2020 (US)	310 (6.6%)	1.07 (3.8%)	0.25 (5.3%)	-0.13 (-1.7%)
Tellus (2002)	10%-2020 (RI)	31 (0.6%)	0.13 (0.4%)	0.00 (0.0%)	0.02 (0.1%)
Tellus (2002)	15%-2020 (RI)	89 (1.8%)	0.23 (0.7%)	0.01 (0.4%)	-0.05 (-0.3%)
Tellus (2002)	20%-2020 (RI)	98 (2.0%)	0.28 (0.8%)	0.02 (0.8%)	-0.07 (-0.4%)

Notes:

- All dollar figures are in constant 2000$.
- The increase in US renewable energy generation reflects the TWh and % increase *relative* to the reference case scenario for the year 2020. The % figures do not equate to the size of the RPS for a variety of reasons: 1) existing renewable generation and new renewable generation that comes on line in the reference case may also be eligible for the RPS, and 2) the RPS is not always achieved, given assumed cost caps in some studies.
- The reference case in most studies reflects an EIA Annual Energy Outlook (AEO) reference case, with some studies making adjustments based on more recent gas prices or altered renewable-technology assumptions. The one exception is UCS (2003), in which the reference case reflects a substantially higher gas-price environment than the relevant AEO reference case.
- The Tellus study models an RPS for Rhode Island, also including the impacts of the Massachusetts and Connecticut RPS policies. All the figures shown in this table for the Tellus study are for the predicted national-level impacts of the regional policies that were evaluated.

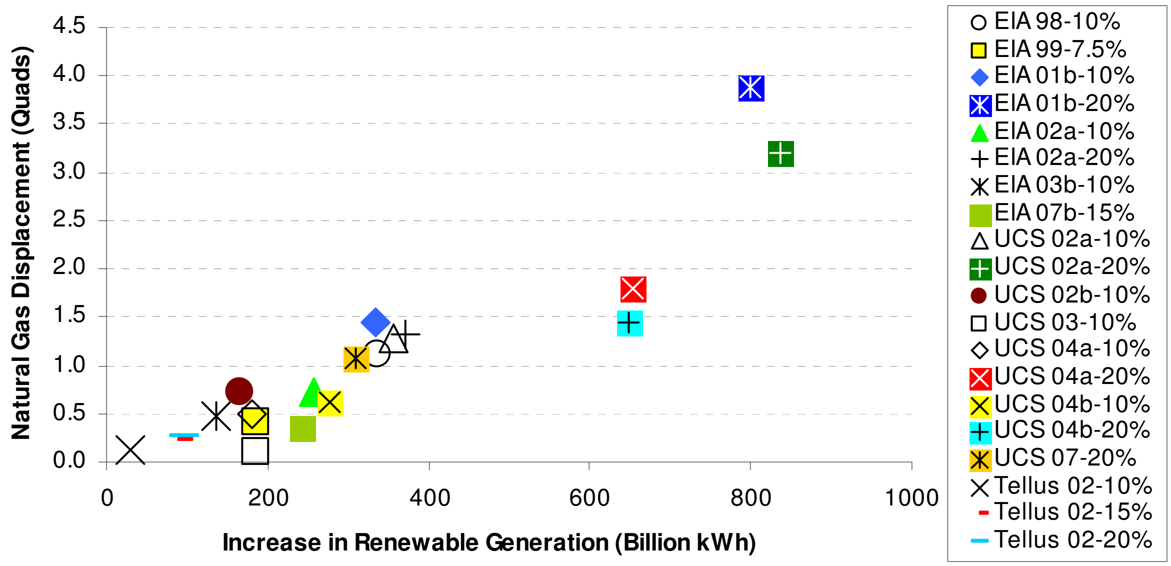


Figure 6. Forecasted Natural Gas Displacement in 2020

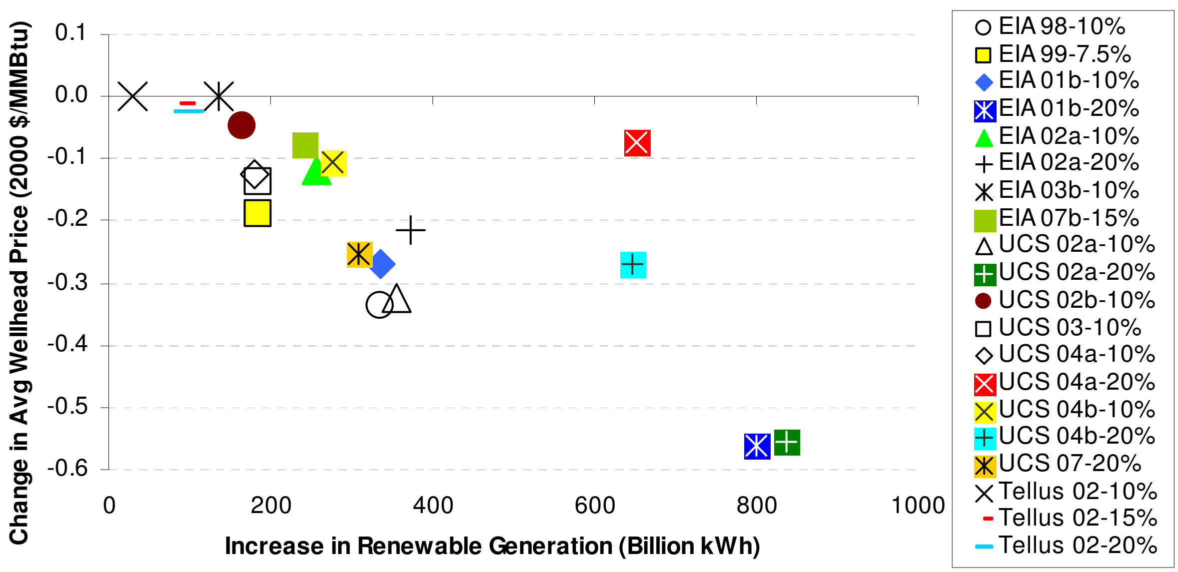


Figure 7. Forecasted Natural Gas Wellhead Price Reduction in 2020

3.2.2 Induced Natural Gas Price Reductions, in Context

The previously presented results show that increased renewable generation is predicted to reduce natural gas consumption and prices while retail electricity prices are predicted to rise in at least some instances. The net predicted effect on US consumer energy bills could be positive or negative, depending on the relative magnitude of the electricity- and natural gas-bill changes.

Figure 8 presents these offsetting effects for a subset of the studies that we reviewed.[30] Although there are variations among the different studies, the present value cost of the cumulative (through 2020) predicted increase in consumer electricity bills (if any) in the RPS

[30] Figure 8 shows the energy bill impacts only for the national RPS studies [i.e., it excludes Tellus (2002)].

cases compared to the reference case is often on the same order of magnitude as the present value benefit of the predicted decrease in consumer natural gas bills. From an aggregate *consumer* perspective, therefore, the net consumer cost of these policies is typically predicted to be rather small, with 13 of 17 RPS analyses even showing net consumer savings (i.e., negative cumulative bill impacts).[31] Clearly, the expected consumer benefit of renewable energy in reducing natural gas prices can be substantial, and ignoring this benefit may cause a substantial bias in any estimate of the net consumer costs of increased renewable energy deployment.

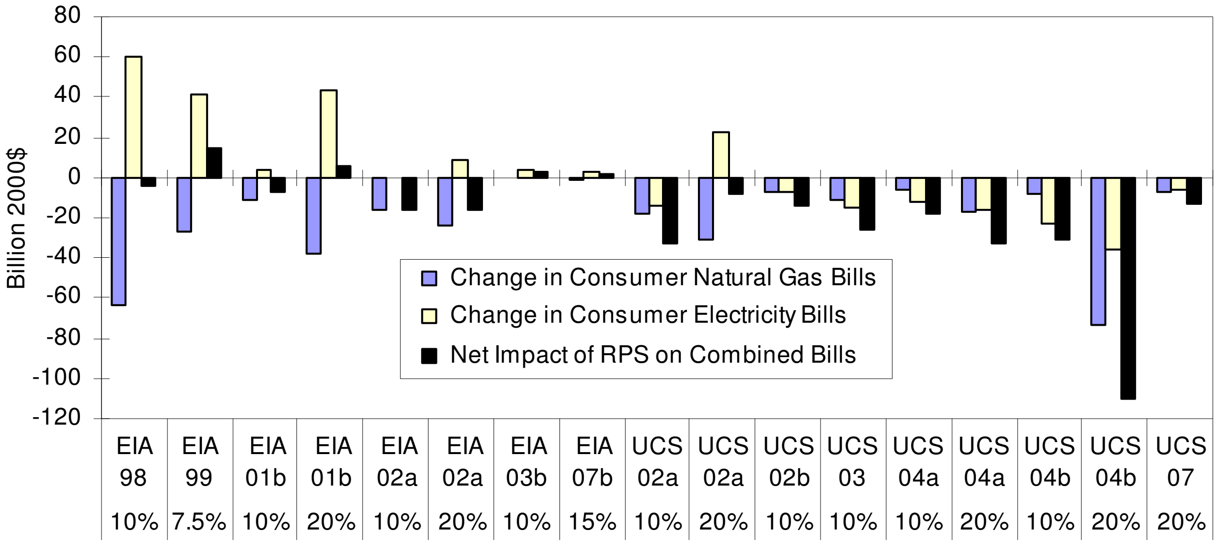
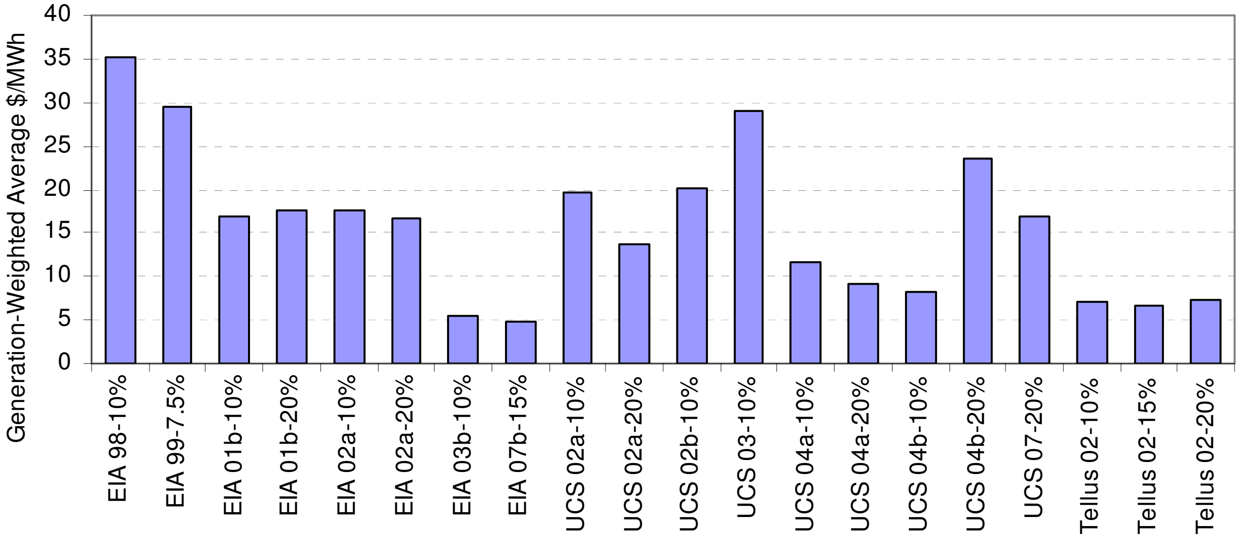


Figure 8. Present Value of RPS Impacts on Natural Gas and Electricity Bills (through 2020, 7% real discount rate)

To put this possible price-reduction benefit in another context, Figure 9 shows the range of consumer benefits delivered by increased renewable energy, by study, expressed in terms of $ per MWh of renewable generation. Here we focus only on the consumer benefits that derive from induced reductions in natural gas prices, and do not consider the positive and negative impacts and costs of renewable energy on other segments of the energy-economy.

Results from these studies suggest that each MWh of renewable energy provides, in aggregate, US consumer gas-price reduction benefits that range from $5 to $35/MWh, with most studies showing a range of $7.50 to $20/MWh. Variations in this value are caused by different implied inverse price elasticities of natural gas supply (defined and discussed in the next section), and by differences in the amount of gas displacement caused by renewable energy. Even at the low end of the range, however, these consumer benefits are sizable.

[31] In several of these studies, RPS cost caps are reached, ensuring that consumers pay a capped price for some number of *proxy* renewable energy credits (and leading to increased electricity prices) while not obtaining the benefits of increased renewable generation on natural gas prices. Accordingly, if anything, Figure 8 underestimates the possible consumer benefits of a well-designed renewable energy program with less-binding cost caps.



Note: We weight the annual gas bill savings per MWh of renewable generation by the amount of yearly renewable generation to derive this weighted average figure. In doing so, we ignore early-year "noise" in the data, and extend the average to the last year of the forecast period (2020 – 2030, depending on the study).

Figure 9. Consumer Gas-Savings Benefits of Increased Renewable Production (in $/MWh)

3.3 Summary of Implied Inverse Price Elasticities of Supply

The *price elasticity of natural gas supply* is a measure of the responsiveness of natural gas supply to changes in the price of the commodity at a specific point on the supply curve, and is calculated by dividing the percentage change in quantity supplied by the percentage change in price. In the case of renewable-energy-induced shifts in the demand for natural gas, however, we are interested in understanding the change in price that will result from a given change in quantity demanded, or the *inverse price elasticity of supply* ("inverse elasticity").

The inverse elasticity provides a convenient, normalized measure by which to compare the price responses predicted by the 13 modeling studies described earlier. The calculation requires annual data on the predicted average US wellhead price of natural gas and total gas consumption in the United States for both the business-as-usual scenario and the policy scenario of increased renewable energy deployment.[32] Because relying on the implied inverse elasticity for any *single* year could be misleading, Figure 10 compares the *average* value of the long-term implicit inverse elasticities among studies.[33] Despite substantial variations among studies and results for individual years (see Wiser et al. 2005), there is some consistency in the *average* long-term inverse elasticities; the overall range is between 0.7 and 4.7, with elasticities from 14 of 20

[32] The specific calculation is:
$E^{-1} = (\text{Wellhead Price}_{\text{business-as-usual}} / \text{Wellhead Price}_{\text{policy}} - 1)/(\text{Gas Demand}_{\text{business-as-usual}} / \text{Gas Demand}_{\text{policy}} - 1)$
Natural gas demand is equivalent to natural gas supply in this instance. The inverse elasticity calculations presented here use US price and quantity data under the assumption that the current market for natural gas is more regional than worldwide in nature (Henning, Sloan & de Leon 2003). Of course, the market for natural gas consumed in the US is arguably a North American market, including Canada and Mexico, with LNG expected to play an increasing role in the future. Trade with Mexico is relatively small, however, and Canadian demand for gas is relatively small compared to US demand. LNG, meanwhile, remains a modest contributor to total US consumption.

[33] Average inverse elasticities are calculated as the average of each year's inverse elasticity, ignoring early-year "noise" in the data and extending to the last year of the forecast period, 2020-2030, depending on the study.

analyses falling between 0.8 and 2.0.[34] This means that each 1% reduction in US natural gas demand is expected to lead to something on the order of a 0.8% to 2% reduction in wellhead gas prices on average.

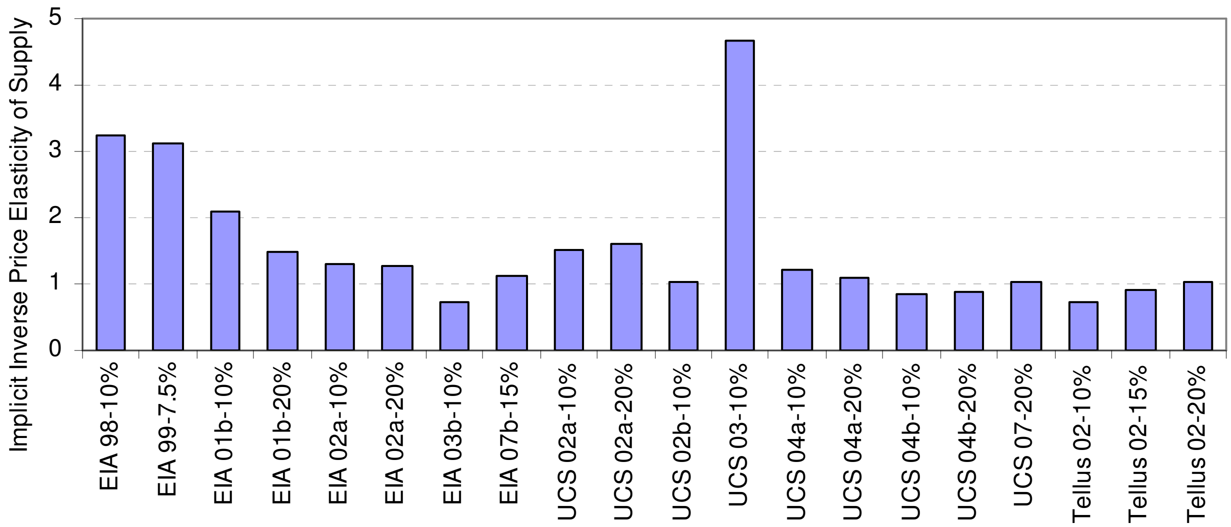


Figure 10. Average Inverse Price Elasticities of Supply

3.4 Benchmarking Elasticities Against Other Models and Empirical Estimates

The energy-modeling results reviewed previously tell a consistent, basic story: reducing the demand for natural gas through the use of renewable energy is expected to lead to lower natural gas prices than would be the case in a business-as-usual scenario. These are modeling predictions, however, which are based on an estimated shape of a natural gas supply curve that is not known with any precision. Furthermore, all of the studies reviewed so far used the same basic model – the EIA's National Energy Modeling System – which raises questions about the degree of confidence we should place in these modeling results. These questions can be at least partly addressed by comparing the NEMS-based implied inverse elasticities presented earlier to those from other energy models, and by benchmarking them against empirical estimates of historical inverse elasticities.

As shown in Wiser and Bolinger (2007), a survey of studies conducted using models other than NEMS found that most use long-term inverse elasticity assumptions that are broadly consistent with, and in some cases higher than, the range shown in Figure 10. For example, studies from the American Council for an Energy-Efficient Economy (ACEEE 2003), the National Petroleum Council (NPC 2003a, 2003b), and the National Commission on Energy

[34] The average inverse elasticity from UCS (2003) is substantially higher than that from most of the other studies. As noted earlier, UCS (2003) evaluated the potential impact of an RPS under a scenario of higher gas prices than in a typical AEO reference case, so that study is not strictly comparable to the others covered in this chapter (specifically, the UCS study includes a more constrained gas supply than most of the other analyses, especially in the later years, and so is likely measuring changes along a steeper portion of the supply curve).

Policy (NCEP 2003) used a model from Energy and Environmental Analysis, Inc. Though not directly comparable to those in our sample, these studies exhibit more-aggressive long-term inverse elasticities, in the range of 4.0. More recently, the California Energy Commission used a model from Global Energy Decisions to measure the gas price suppression impact; it found even more-aggressive long-term inverse elasticities in the neighborhood of 5.0 (CEC 2007). Other models used in a Stanford Energy Modeling Forum study were more consistent with NEMS (EMF 2003). This general level of cross-model consistency provides at least some comfort that the renewable energy studies within our sample are modeling this effect within reason, and perhaps even conservatively.

Empirical research on energy elasticities has focused almost exclusively on the impact of supply shocks on energy *demand* (demand elasticity) rather than the impact of demand shocks on energy *supply* (supply elasticity). As a result, there are few empirical estimates of supply elasticities against which to benchmark the modeling output described earlier. Nonetheless, as discussed in Wiser and Bolinger (2007), the few published empirical estimates of historical long-term inverse elasticities for gas, coal, and oil are positive, and are not wildly out of line with the long-term inverse elasticity of natural gas implied by the modeling output presented earlier. Though more work is certainly warranted in this area, the extant literature at least suggests that the models are evaluating price responsiveness within reason and within the limits of current knowledge.

4. Conclusions

Renewable energy has historically been supported primarily because of its perceived environmental, economic development, and national-security benefits. More recently, sharp price escalations in wholesale electricity and natural gas markets have led to renewed discussions about the potential risk mitigation value of renewable resources in the United States and elsewhere. Specifically, by displacing variable-priced natural gas-fired generation, fixed-price renewable generation not only directly mitigates fuel price risk, but also reduces demand for natural gas, which in turn places downward pressure on natural gas prices – a benefit that flows through to all gas-consuming sectors of the economy.

This paper has explored both of these possible risk mitigation benefits. We find that the direct risk mitigation benefit of renewable generation is not always recognized in quantitative resource evaluations, which often use uncertain natural gas price forecasts to compare the levelized cost of gas-fired generation to the cost of fixed-price renewables, and therefore do not consider the consumer benefits of price stability. Our analysis shows that, over the past seven years at least, substituting natural gas forward prices – i.e., prices that can be locked in to create price certainty – for the uncertain price forecasts would have significantly improved the relative economics of fixed-price renewables.

In addition, our review of results from 13 studies that model the economy-wide impact of increased renewables penetration suggests that each 1% reduction in nationwide demand for natural gas will result in a long-term wellhead price reduction somewhere on the order of 0.8% to 2.0% on average. Price reductions are likely to be even larger in the short-term (and perhaps also in the long-term, according to some models). In many cases, this gas price suppression is predicted to be sizable enough to outweigh any incremental costs associated with increased renewables penetration – even without considering the direct risk mitigation benefit discussed above.

Both of these findings support the notion that, on an economic basis alone, renewable generation should play a larger role in generating portfolios. This, of course, is the same message that our late colleague, Shimon Awerbuch, so tenaciously espoused throughout his distinguished career. Unfortunately, this message and its underlying concepts have only recently spread beyond the academic community and taken root among energy policy- and decision-makers, who have become more receptive in this era of sharply higher and volatile fuel prices, energy insecurity, more-competitive renewable generation technologies, and growing concern over global climate change. In turn, the composition of generation portfolios around the world has only recently begun to shift more towards renewables. We regret that Shimon, a thinker before his time (and well ahead of the rest of us), will not be here to witness the full transformation to this more sustainable – and less-risky – energy future.

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