Apples with apples

Accounting for fuel price risk in comparisons of gas-fired and renewable generation

Mark Bolinger and Ryan Wiser explain how the common practice of using gas price forecasts in long-range resource planning exercises could bias results – and bias resource decisions – away from renewables.[1]

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 US Energy Information Administration (EIA), natural gas combined-cycle and combustion turbine power plants accounted for 96% of the total generating capacity added in the US between 1999 and 2002 – 138 GW out of a total of 144 GW. Looking ahead, the EIA expects that gas-fired technology will account for 61% of the 355 GW new generating capacity projected to come on-line in the US up to 2025, increasing the nationwide market share of gas-fired generation from 18% in 2002 to 22% in 2025. While the data are specific to the US, natural gas-fired generation is making similar advances in other countries as well.

With increasing competition for dwindling domestic natural gas supplies, it is likely that gas prices in the US will continue to be at least as volatile as they have been in the past. Figure 1 shows 'first-nearby' natural gas futures prices (i.e. on contracts due to expire imminently) on a daily basis, going back to the inception of trading on the New York Mercantile Exchange (NYMEX)[2] 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, many of the 'lesser' price spikes during the early 1990s nevertheless represent doublings in price, or even greater increases. Figure 1 also shows the NYMEX gas futures strip from mid December 2003, to the right of the vertical dashed red line, which depicts the prices that could be 'locked in', at that time, for the next six years. Whereas short-term gas futures prices have ranged from US$1–3/MMBTU (million British thermal units) for much of their trading history (apart from the two major price spikes), the market was, in mid December 2003, projecting prices to generally range between $4.5–5/MMBTU over the next six years.

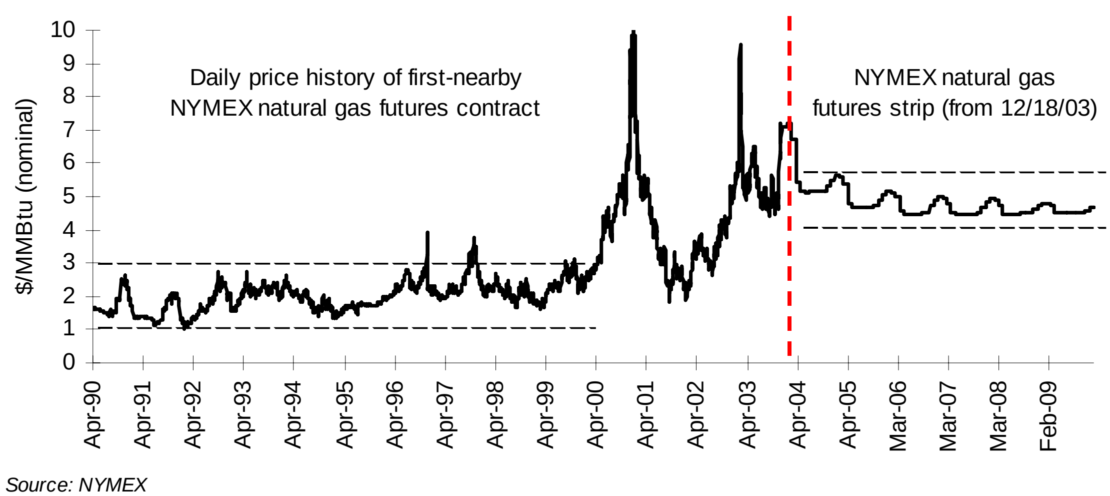

Figure 1. NYMEX natural gas futures prices. Source: NYMEX

This is particularly noteworthy considering that natural gas prices (and gas price volatility) have a significant impact on wholesale electricity prices (and price volatility). The cost of natural gas accounts for *more than half* of the levelized cost of energy from a new combined-cycle gas turbine, and *more than 90%* of its operating costs. Moreover, with the emergence of competitive wholesale electricity markets, gas-fired plants are often the marginal units that set the market-clearing price for *all* generators in the market, allowing natural gas price volatility to flow directly through to wholesale electricity price volatility. Clearly, the variability of gas prices poses a major risk to both buyers and sellers of gas-fired generation.

Against this backdrop of increasingly volatile natural gas prices, renewable energy resources – which by their nature are immune to natural gas fuel price risk – can provide a real economic benefit. Unlike many contracts for natural gas-fired generation, renewable generation, such as wind or geothermal power, is typically sold in the US under long-term *fixed-price* contracts. Assuming that electricity consumers value long-term price stability,[3] 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 with the *hedged* or *guaranteed* cost of new natural gas-fired generation, rather than with projected costs based on uncertain gas price forecasts. To do otherwise would be to compare apples with oranges: by their nature, renewable resources carry no natural gas fuel price risk, and if the market does value this attribute, then the most appropriate comparison is to the hedged cost of natural gas-fired generation.[4]

Hedging the risk: selecting the appropriate point of comparison

To hedge natural gas price risk, a retail electricity supplier can choose among a number of gas-based financial and physical hedging instruments, can purchase fixed-price gas-fired electricity (in which case the generator may wish to hedge using gas-based financial or physical instruments), or can, of course, purchase fixed-price renewable electricity.[5] Financial gas-based hedges include futures (or, more generically, forwards) swaps, options on futures, or some combination or derivation thereof, such as collars. Physical hedges include long-term fixed-price gas supply contracts and natural gas storage.

As is shown in Figure 2, each of these hedging instruments falls into one of two categories:

- those creating a *flat payout pattern*, immune to gas price movements in either direction; for example, gas futures, swaps and fixed-price physical supply, as well as fixed-price renewable generation
- those creating a *contingent payout pattern*, which protects against adverse gas price movements while allowing participation in favourable gas price movements; for example, gas options and storage.

To fairly evaluate fixed-price renewable and variable-price gas-fired electricity contracts on an ‘apples with apples’ basis, we must look to those instruments that provide a *hedged payout pattern* similar to that of renewables – that is, flat and symmetrical, immune to both increases and decreases in gas prices. As Figure 2 shows, such instruments 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 for modelling and resource planning studies that compare – either explicitly or implicitly – renewable to gas-fired generation.

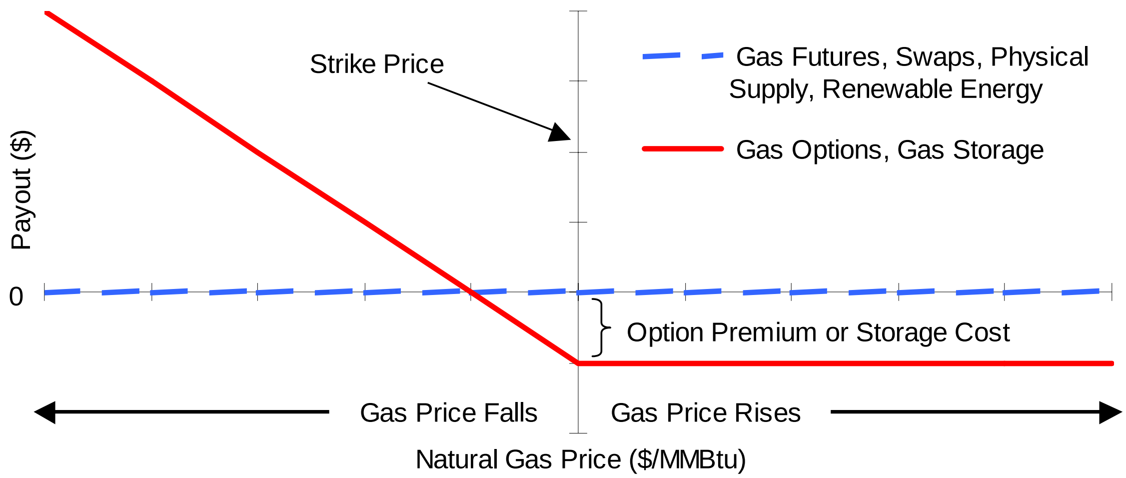

Figure 2. Payout patterns for various hedging instruments (hedge plus underlying)

Forward gas prices vs reference case forecasts

Utility resource planners and electricity analysts conducting such studies, however, 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 forecasts compare to actual forward gas prices that can be locked in to create price certainty? If they are similar, then one might conclude that forecast-based modelling and planning exercises are in fact approximating an 'apples with apples' comparison, and no further consideration is necessary. If, however, forward gas prices systematically differ from long-term gas price forecasts (if there is, say, a cost to hedging, or if forecasts are out of tune with market expectations), then the use of such forecasts in resource modelling, planning, and acquisition exercises will yield results that are biased in favour either of renewable generation (if forward prices are below price forecasts) or natural gas-fired generation (if forward prices exceed price forecasts).

The data necessary to address this question are deceptively simple: all that is required is 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,[6] obtaining long-term forward gas prices – and in particular those of sufficient duration to be of interest, given the 10–25 years of price stability offered by most contracts for renewable generation – presents a greater challenge. Despite best efforts to obtain a larger sample, this analysis is limited to comparisons from November 2000 to November 2003, and for terms not exceeding ten years. Specifically, this limited sample of forward contracts and price forecasts includes:

- two-year, five-year and ten-year natural gas swaps offered by Enron in November 2000 and 2001, compared with reference case natural gas price forecasts from the EIA's *Annual Energy Outlook 2001* and *2002*, respectively
- the six-year NYMEX natural gas futures strip from November 2002, compared with the reference case gas price forecast contained in *Annual Energy Outlook 2003*
- a seven-year physical gas supply contract between the supplier, Williams, and the California Department of Water Resources signed in November 2002, again compared with the reference case gas price forecast contained in *Annual Energy Outlook 2003*.
- the six-year NYMEX natural gas futures strip from October 2003, compared with the reference case gas price forecast contained in *Annual Energy Outlook 2004*

Each of these five comparisons reveals that, in recent years, forward natural gas prices have traded above EIA reference case price forecasts, sometimes significantly so. Figure 3 consolidates into a single graph the resulting premiums from each of these comparisons, calculated by subtracting the levelized forecast price from the levelized forward price, and expressed in terms of both $/MMBTU and US cents/kWh, assuming a heat rate of 7000 BTU/kWh.

As shown, the magnitude of the empirically derived premiums (derived 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 cents/kWh (0.4 cents/kWh on average). One cannot easily extrapolate these findings beyond the period from November 2000 to November 2003, or to contract terms longer than those examined. Nonetheless, it is at least apparent that utilities and analysts who have conducted resource planning and modelling studies based on EIA reference case gas price forecasts over this period have produced 'biased' results (i.e. presuming that long-term price stability is valued). These biased results favour variable-price, gas-fired over fixed-price renewable generation, potentially to the tune of around 0.3–0.6 cents/kWh on a levelized cost basis.

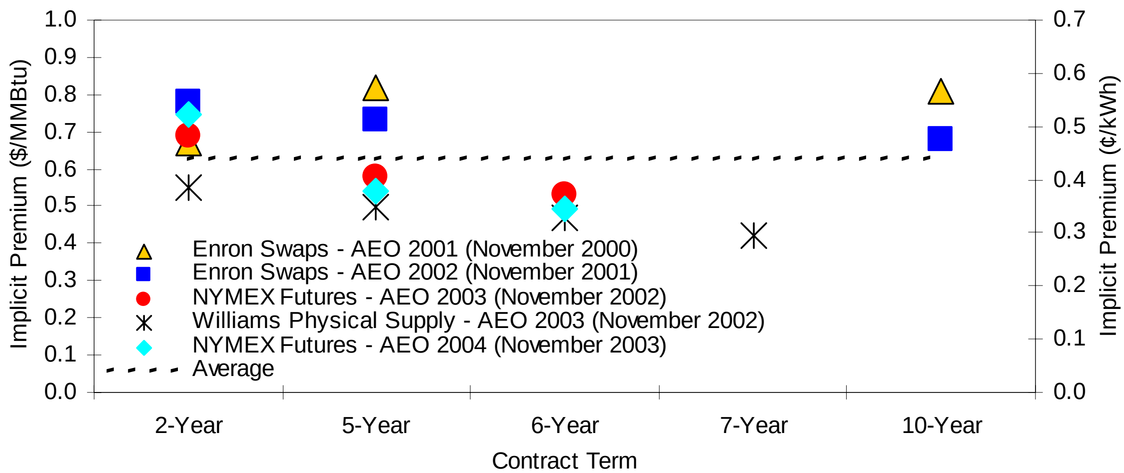

Figure 3. Levelized forward-forecast premiums (assuming 7000 BTU/kWh)

Other forecasts – larger premiums

Given that they are publicly available, highly documented and reviewed, and used widely in modelling exercises and resource planning processes throughout the US, EIA reference case gas price forecasts are a reasonable starting point for our analysis. The EIA's forecasts, however, are by no means the only long-term gas price forecasts available to market participants. Obviously, unless 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 3 would change had we compared forward prices to some forecast other than the EIA's, a number of different long-term gas price forecasts were looked at, 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 been higher – and often substantially so – than most other forecasts generated from 2000–2002 and used by utilities and analysts. These findings suggest that the premiums observed relative to the EIA reference case forecasts would be *even larger* when comparing forward prices to many of these other commonly used gas price forecasts.

For example, had we instead compared the November 2001 ten-year natural gas swap with the gas price forecast contained in Idaho Power's resource plan, we would have observed a ten-year levelized premium of $1.29/MMBTU – that is, *nearly twice as large* as the $0.68/MMBTU benchmarked against the EIA reference case forecast. This translates to a difference of 0.9 cents/kWh at an aggressive heat rate of 7000 BTU/kWh, and suggests that, had Idaho Power opted to use forward market data rather than forecast data, its comparisons between renewable and gas-fired generation may have looked significantly different. With most other forecast comparisons yielding similar results (though not as great in magnitude), it is clear that utilities and analysts that have used these other (non-EIA) forecasts to compare fixed-price renewable with variable-price gas-fired generation have obtained results that are even more 'biased' in favour of gas-fired generation than those resulting from EIA reference case comparisons.

Possible explanations for premiums

How can one explain the existence of price premiums as high as $0.8/MMBTU levelized over ten years, relative to EIA reference case gas price forecasts – or even higher relative to other gas price forecasts? Assuming that data issues are not the cause,[7] there are at least two different explanations that could either partially or wholly account for such sizeable differences between natural gas forwards and forecasts. These are:

- *Hedging is not without cost* **–** 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).[8] Alternatively, the incremental cost of hedging could reflect high *transaction costs*, manifested in wide bid-offer spreads that ensure that the consumer/hedger always pays more than the 'true' (e.g. mid-market) price. On the basis that hedging is not without cost, the premiums presented in Figure 3 might be considered the 'hedge value' of renewable generation; in other words, renewable generation provides price stability without incurring these 'incremental' hedging costs.
- *The forecasts are out of tune with market expectations* – Under this explanation, it is the gas price forecasts themselves that are at issue – not just the EIA's reference case, but virtually all of the forecasts examined over the sample period – and have been biased downwards relative to the market's expectations of future gas prices. If this is true, then the empirical observations of premiums may not necessarily indicate that there is an incremental cost of hedging *per se*. Instead, forward prices may in fact be unbiased estimators of future spot prices, and the premiums observed may simply be due to the use of forecasts that have been seriously out of tune with market expectations over the sample period. If true, this calls into question the use of these forecasts for *any* purpose.

Each of these potential explanations for the existence of empirical premiums between forwards and forecasts is theoretically plausible, yet not fully satisfactory on its own. It is perhaps more likely that some combination of these two (and maybe other) explanations are driving the empirical findings of a premium.

Implications

Regardless of the explanation for (or interpretation of) the empirical findings, however, the basic implications remain the same: *one should not blindly rely on gas price forecasts when comparing fixed-price renewable with 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 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 resource comparisons or investment decisions if a more certain source of data (forwards) existed. Accordingly, assuming that long-term price stability is valued, the most appropriate way to compare the levelized cost of these resources in both cases would be to use forward natural gas price data – i.e. prices that can be locked in to create price certainty – as opposed to uncertain natural gas price forecasts. This article suggests that had utilities and analysts in the US done so over the sample period from November 2000 to November 2003, they would have found gas-fired generation to be at least 0.3–0.6 cents/kWh more expensive (on a levelized cost basis) than otherwise thought. With some renewable resources, in particular wind power, now largely competitive with gas-fired generation in the US (including the impact of the federal production tax credit and current high gas prices), a margin of 0.3–0.6 cents/kWh may in some cases be enough to sway resource decisions in favour of renewables.

Mark Bolinger and Ryan Wiser are researchers at Lawrence Berkeley National Laboratory in Berkeley, California, US.
e-mail: MABolinger@lbl.gov
RHWiser@lbl.gov

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website: http://eetd.lbl.gov/ea/EMS/reports/53587.pdf.

Notes

1. See also Shimon Awerbuch's article 'Determining the real cost: Why renewable power is more cost-competitive than previously believed', *Renewable Energy World*, March–April 2003, pp. 52–61.
2. NYMEX natural gas futures contracts are deliverable to the Henry Hub in Louisiana, a major market centre that can be thought of as being downstream from the wellhead, yet upstream from electricity generators (that is, the price of gas delivered to electricity generators typically exceeds the Henry Hub price, which in turn typically exceeds wellhead prices).
3. Specifically, the presumption here is that consumers' valuation of price stability exceeds the cost (if any) of achieving stable prices from gas-fired generation. Since most renewable resources provide price stability intrinsically (i.e. at no additional cost), it is therefore proper to compare their costs to the *hedged* cost of gas-fired generation.
4. Separate from the 'hedge value' of renewable energy discussed in this article, long-term fixed-price renewable energy contracts may also provide incremental value over other more conventional forms of hedging (for instance, natural gas forward and swap contracts) in the form of both lower gas prices and reduced credit risk. For example, to the extent that it displaces gas-fired generation, development of new renewable generation may reduce future gas prices to all sectors of the economy. Furthermore, because they are backed by a physical generation asset with low, stable operating costs, long-term fixed-price renewable energy contracts may involve *less* credit risk than long-term fixed-price natural gas contracts of similar duration. These two potential benefits – which are not included in our analysis – may become increasingly important over longer contract terms of 15–25 years.
5. Similarly, investments in energy efficiency (for instance, 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.
6. The EIA forecasts, for instance, are publicly available and updated every year.
7. Three possible data issues might be of concern. First, the forward prices sampled might be distorted upwards (for instance, due to thin markets and/or price manipulation), which could artificially create or inflate a premium over price forecasts. Second, if the forward prices were sampled significantly earlier or later than the generation of the forecasts, then the observed premiums could simply be the result of a fundamental change in market expectations in the interim. Though not discussed here, we have examined both of these potential issues and believe them to be of little or no concern. Finally, even if the *quality* of the sample were beyond reproach, the *small size* of the sample admittedly limits the possibility of drawing strong conclusions about the existence or size of any premium between forward prices and price forecasts.
8. For more information on CAPM, see Shimon Awerbuch's article (note 1).