LBNL-6103E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices

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March 2013

The work described in this report was funded by the U.S. Department of Energy's Wind Power Program, within the Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231.

Disclaimer

Acknowledgments

The work described in this report was funded by the U.S. Department of Energy's Wind Power Program, within the Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231. Particular thanks go to Patrick Gilman, Cash Fitzpatrick, Mark Higgins, and Rich Tusing of the U.S. DOE for their support of this work. The author would also like to thank the following individuals for reviewing earlier drafts of this manuscript: Andrew Mills, Ryan Wiser, and Mark Zimring (LBNL), Eric Lantz and Jeff Logan (NREL), and Ron Binz (Public Policy Consulting). Of course, any remaining errors or omissions are the author's sole responsibility.

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Executive Summary

Expanding production of the United States' vast shale gas reserves in recent years has put the country on a path towards greater energy independence, enhanced economic prosperity, and (potentially) reduced emissions of greenhouse gases and other pollutants. The corresponding expansion of gas-fired generation in the power sector – driven primarily by lower natural gas prices – has also made it easier and cheaper to integrate large amounts of variable renewable generation, such as wind power, into the grid.

At the same time, however, low natural gas prices have suppressed wholesale power prices across the nation, making it harder for wind and other renewable power technologies to compete on cost alone – even despite their recent cost and performance improvements. A near-term softening in policy-driven demand from state-level renewable energy mandates, coupled with a possible phase-out of a key federal tax incentive over time, may exacerbate wind's challenge in the coming years.

As wind power finds it more difficult to compete with gas-fired generation on the basis of near-term cost, it will increasingly need to rely on other attributes, such as its "portfolio" or "hedge" value, as justification for inclusion in the power mix. This article investigates the degree to which wind power can still serve as a cost-effective hedge against rising natural gas prices, given the significant reduction in gas prices in recent years, coupled with expectations that prices will remain low for many years to come. It does so by drawing upon a rich sample of long-term power purchase agreements ("PPAs") between existing wind generators and electric utilities in the U.S., and comparing the contracted prices at which utilities will be buying wind power from these existing projects for decades to come to a variety of long-term projections of the fuel costs of gas-fired generation modeled by the Energy Information Administration ("EIA").

The wind PPA sample – consisting of 287 contracts totaling more than 23.5 GW of operating wind capacity in the U.S. – exhibits a high degree of long-term price stability. On average and in real dollar terms, the buyers of the wind energy in the PPA sample will pay no more per MWh twenty years from now as they do today. In contrast, natural gas prices are difficult to lock in for any significant duration, making it hard to capitalize on today's low prices. Although short-term gas price risk can be effectively hedged using conventional hedging instruments (like futures, options, and bilateral physical supply contracts), these instruments come up short when one tries to lock in prices over longer terms – e.g., greater than five or ten years. It is over these longer durations where inherently stable-priced generation sources like wind power hold a rather unique competitive advantage.

Comparing the wind PPA sample to the range of long-term gas price projections reveals that even in today's low gas price environment, and with the promise of shale gas having driven down future gas price expectations, wind power can still provide long-term protection against many of the higher-priced natural gas scenarios contemplated by the EIA. This is particularly true among the most recent wind PPAs in the sample, which likely better represent current wind pricing, at least on a national average basis. These newer wind contracts not only provide ample long-term hedge value, but on average are also directly competitive with gas-fired generation in the near term.

1. Introduction

One of the largest energy supply developments of the past decade has been the application of horizontal drilling in combination with hydraulic fracturing to unlock seemingly massive deposits of "shale gas" – natural gas that was previously considered to be trapped in shale rock formations. In the United States, where the enabling technology was developed and first applied on a large scale, the U.S. Energy Information Administration ("EIA") estimates that shale gas accounted for 34% of total domestic natural gas production in 2011, up from 23% in 2010 and just 4% in 2005, and projects that shale gas' share of domestic production will increase to 40% by 2018 and 50% by 2037 (EIA 2012a).

Not only has its proportional contribution increased; shale gas has also played a major role in reversing what had been a declining trend in absolute overall domestic gas production in the U.S. since 2001. After hitting a low of about 18 trillion cubic feet ("Tcf") produced in 2005, domestic gas production increased by nearly 5 Tcf through 2011, led by a more than 7 Tcf increase in shale gas production (i.e., production from non-shale resources continued to decline over this period). Looking ahead, the EIA projects that total domestic gas production will increase by another 3.6 Tcf per year by 2020, 3.2 Tcf of which will be shale gas (EIA 2012a).

One consequence of expanding domestic shale gas production is less need to import natural gas into the U.S., either from Canada or Mexico via pipeline or from other countries in the form of liquefied natural gas ("LNG"). At the same time, with the price of natural gas significantly higher in parts of Asia and Europe (where natural gas prices are more closely linked to oil prices) than it is in the U.S., opportunities to export domestic gas surplus have grown.[1] The EIA reports that in 2011, rising exports and lower imports reduced net gas imports to 1.95 Tcf, the lowest level since 1992 (EIA 2012d), and projects that the U.S. will be a net exporter of LNG by 2016, and a net exporter of natural gas overall by 2020 (EIA 2012a).

This "gas revolution" in the U.S. is having, and should continue to have, a profound effect on the electric power sector. With ample supply pushing natural gas prices down to historic lows – spot gas prices fell below $2/MMBtu in April 2012 – aggressive fuel switching from coal to natural gas has been occurring in the power sector. Coal-fired generation fell from 49.6% of all U.S. power generation in 2005 to 42.2% in 2011, while natural gas-fired generation grew from 18.8% to 24.8% (EIA 2012a). Additional fuel-switching occurred in 2012, with coal expected to have dropped to 38% of all electricity generation while natural gas rose to 30% (EIA 2012a). Looking ahead, the implementation of air quality regulations from the Environmental Protection Agency – principally the Mercury and Air Toxics Standards ("MATS") and the Clean Air Interstate Rule ("CAIR") or its successor – is likely to further benefit gas relative to coal.

[1] As of January 30, 2013, twenty-three entities had applied to the U.S. Department of Energy for licenses to export LNG totaling 29.41 Bcf/day (see http://www.fossil.energy.gov/programs/gasregulation). Only one of these applications – for 2.2 Bcf/day from Sabine Pass Liquefaction, LLC – had so far been approved (for export to countries with which the U.S. does not have a free trade agreement) and was under construction. How many of these facilities are ultimately approved and built remains to be seen, as the global diffusion of horizontal drilling and hydraulic fracturing technology may ultimately reduce the need for LNG exports (Krauss 2013).

The ongoing switch from coal-fired to gas-fired generation in the U.S. is, arguably, a positive development within the power sector, on several fronts. Natural gas is cleaner-burning than coal, and therefore emits fewer criteria pollutants (NOx, SOx, particulates) and greenhouse gases when combusted to generate electricity.[2] Gas-fired generation is also more flexible than coal-fired generation (in terms of its ability to ramp output up and down), which provides a number of system benefits, including greater ease in integrating variable renewable generation sources like wind and solar into the nation's power grids.[3] These renewable power technologies generate electricity without direct emissions and with very little water use, and help to diversify the nation's power mix, thereby protecting against future adverse impacts (be they environmental, cost-related, and/or security-related) from any single technology or fuel.

On the other hand, the impact of shale gas development on natural gas and wholesale power prices has also made it harder for wind and solar to compete with gas-fired generation. Fuel costs make up the vast majority of the operating cost of gas-fired generation, so when fuel costs are low, so is the cost of gas-fired generation. And with gas-fired generation commonly serving as the marginal supply resource that sets the market clearing price in wholesale power markets in many parts of the country, there is a strong correlation between natural gas fuel costs and wholesale power prices in most parts of the U.S.

As an example of the impact of low natural gas prices on the relative economics of renewable energy, at a delivered gas price of $4/MMBtu, fuel costs account for roughly 85% of the total operating cost – of around $30/MWh – of an efficient combined-cycle gas turbine (EIA 2010).[4] While some wind power projects in the U.S. that are sited in excellent wind resource areas are already selling power to utilities at prices in the neighborhood of $30/MWh (a "post-incentive" price that reflects federal and state government incentives received), in general, $30/MWh is difficult for any type of non-gas generator to compete with.

As such, there is a risk that an acute focus on cheap natural gas in the near-term could slow or delay the transition to cleaner, more-sustainable forms of power generation, such as wind and solar, over longer terms, and that the U.S. could, as a result, end up heavily dependent on gas-fired generation (Jacoby et al. 2012). This may be of particular concern at present, given that state renewables portfolio standards ("RPS") are unlikely to drive as much demand for wind power over the next few years as they have in recent years (BNEF 2012), and as the federal production tax credit ("PTC") for wind – which helps to make the cost of wind generation more

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[2] Though gas-fired generation produces less CO_2 per MWh than coal-fired generation during combustion, there is nevertheless the potential for methane (CH_4) – which has a higher global warming potential than carbon dioxide – to leak into the atmosphere at various stages of natural gas production and transportation. Some studies contend that these "fugitive" emissions can be significant, particularly with shale gas development, thereby greatly impacting the life-cycle greenhouse gas emissions of gas-fired generation (Howarth et al. 2011, 2012), while others present evidence to the contrary (Cathless et al. 2012, JISEA 2012).

[3] Furthermore, with natural gas prices at historically low levels, the cost of integrating these variable resources has declined. For example, as part of its integrated resource planning process, PacifiCorp recently released a draft study that estimates the cost of integrating wind power on PacifiCorp's system to be $1.89/MWh, down sharply from $9.70/MWh when the study was last conducted in 2010 (PacifiCorp 2012). This 80% reduction in wind integration cost is driven primarily by lower natural gas prices.

[4] Not surprisingly, then, average wholesale power prices across the United States in 2012 ranged from roughly $20/MWh to $40/MWh, reflecting the influence of low natural gas prices.

competitive with other forms of power generation – faces serious risk of being phased out in the coming years (AWEA 2012c).

At this time when wind, solar, and other renewable generating technologies are facing reduced policy support and are having difficulty competing with gas-fired generation in the near-term on cost alone, it is useful to keep in mind other "non-cost" attributes that may help to justify the continued addition of fuel-free renewables to the power mix. In addition to the environmental benefits mentioned above, another important attribute – and the focus of this article – is the ability of wind and other fuel-free renewables to deliver a stable-priced product over very long time frames. In other words, adding wind power to a portfolio of generating assets will partially hedge or insulate that portfolio against the risk of rising fuel costs over the long term.

This "hedge value" that wind and other fuel-free renewables provide has been studied in the past – though primarily during periods of high gas prices and high gas price volatility – using a variety of methods (Awerbuch 1993, 1994, 2003; Bachrach et al. 2003; Bolinger et al. 2006; Bolinger and Wiser 2008; Huber 2012; Humphreys and McClain 1998; Kahn and Stoft 1993; Wiser and Bolinger 2007). This article builds on the existing literature by taking a comparatively simple and empirically grounded approach to demonstrating the long-term hedge value of wind power. Specifically, it draws upon a rich sample of long-term power purchase agreements between existing wind generators and electric utilities in the United States, and compares the contracted prices at which utilities will be buying wind power from these existing projects for decades to come to a variety of long-term projections of the fuel costs of gas-fired generation. This comparison reveals that recognizing the long-term hedge value of wind power is just as relevant today, at a time of historically low natural gas prices, as it has been in the past when gas prices have been higher.

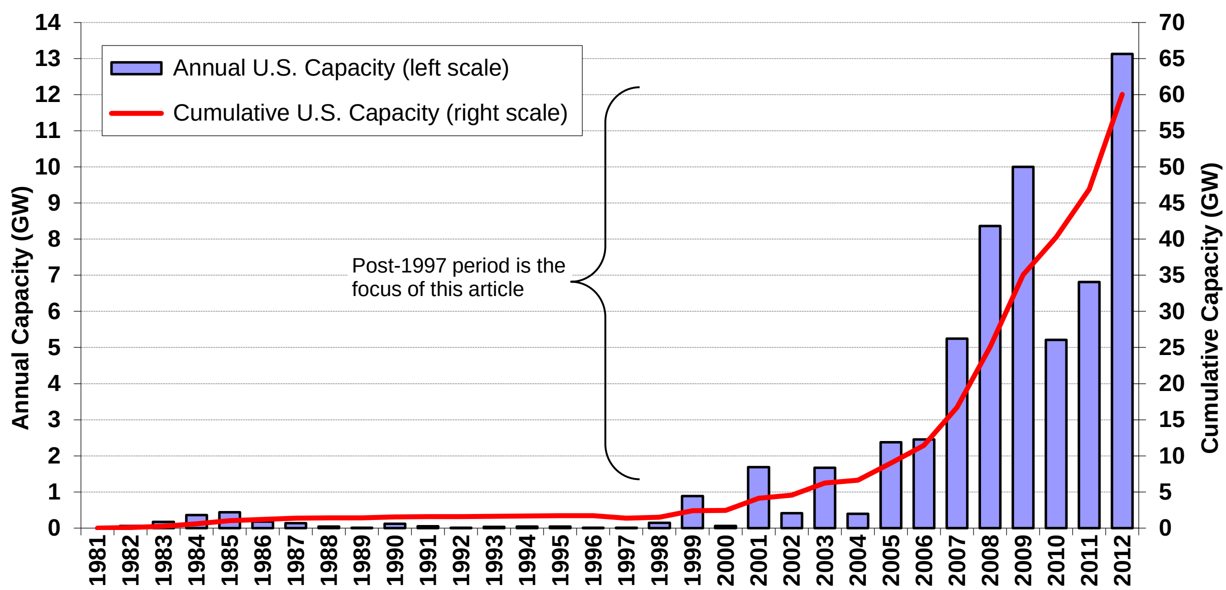
This article proceeds as follows. Section 2 makes the case for valuing wind power as a long-term natural gas price hedge by contrasting the characteristics of a large sample of wind power purchase agreements ("PPAs") to the shortcomings of conventional gas price hedging instruments like futures and options contracts. Although these conventional hedging instruments can be used effectively to hedge gas price risk in the near-term, they come up short when one tries to use them to lock in prices over longer terms – e.g., over the average 20-year duration of a wind PPA. Section 3 sets up an empirical comparison between wind power prices from this PPA sample and long-term natural gas price projections, in order to explore whether wind power can provide this long-term hedge in a cost-effective manner. Section 4 presents the comparison graphically and discusses results, and Section 5 draws conclusions.

2. The Case for Wind as a Long-Term Natural Gas Price Hedge

This section makes the case that considering wind power as a long-term natural gas price hedge is just as relevant today – in an environment of low gas prices – as it has been in the past when gas prices have been higher and more volatile. It does so by first describing the characteristics of a sample of long-term PPAs through which wind power projects in the U.S. sell their power to utilities and other power purchasers, highlighting the inherent price stability of such contracts. Then it proceeds with an overview of current natural gas prices in the U.S., highlighting the difficulties of locking in today's low prices – at least for any length of time – using conventional hedging instruments.

2.1 Wind PPA Sample Exhibits Long-Term Price Stability

At the end of 2012, there were more than 60,000 MW (60 GW) of installed wind power capacity in the U.S. (AWEA 2012b), some of it dating back to the early 1980s. As shown in Figure 1, however, roughly 58.8 GW of this amount, or 98% of the cumulative total, have been built since 1997. Given the overwhelmingly disproportionate weighting of this more-recent period, the remainder of this article focuses on just this post-1997 period in the history of wind power in the U.S.



Source: AWEA 2012b

Figure 1. Annual and Cumulative Growth in U.S. Wind Power Capacity

After subtracting out 13.75 GW of post-1997 wind power capacity that operate on a "merchant" basis (i.e., selling power into local spot markets, rather than bilaterally to a dedicated power purchaser through a long-term PPA), another 9.1 GW of capacity that are owned by electric utilities (and therefore do not involve a sale of wholesale power), 0.3 GW that are interconnected and operate "behind the meter" (i.e., offsetting retail power purchases, rather than selling wholesale power), and 0.4 GW built in Alaska, Hawaii, and Puerto Rico (presumed to be outliers due to their remote locations and/or challenging construction environments), the total possible universe of post-1997 wind power capacity selling power through long-term PPAs comes to 35.4 GW. Out of this possible universe, Lawrence Berkeley National Laboratory has collected pricing terms from a sample ("the LBNL sample") of 287 separate wind power PPAs totaling 23.5 GW, and therefore representing 67% of the total possible universe of wind projects (in capacity terms).[5]

As shown in Table 1, the wind projects whose PPAs are captured within the LBNL sample are distributed throughout the US, with at least one project in all nine U.S. census divisions, resulting in fairly broad sample representation (in total, 29 states are represented in the sample). In percentage terms, the LBNL sample is most under-represented in the New England census division (where 86% of the post-1997 installed wind capacity selling energy through a PPA is not represented), followed by the East North Central division (54% missing) and West South Central division (50% missing). In MW terms, the LBNL sample is missing the most capacity in the West South Central division (3,971 MW missing),[6] followed by the East North Central division (2,313 MW missing) and the Pacific division (2,105 MW missing).

Table 1. LBNL PPA Sample Overview by U.S. Census Division

Census Division	Possible PPA Universe (MW)	LBNL PPA Sample (MW)	Capacity Missing (%)	Capacity Missing (MW)
New England	417	59	86%	358
Middle Atlantic	908	769	15%	139
East North Central	4,309	1,996	54%	2,313
West North Central	8,244	6,820	17%	1,424
South Atlantic	342	241	30%	101
East South Central	27	27	0%	0
West South Central	8,012	4,041	50%	3,971
Mountain	5,777	4,347	25%	1,430
Pacific	7,334	5,229	29%	2,105
Total U.S.	**35,370**	**23,529**	**33%**	**11,841**

The degree to which underrepresentation in these regions results in overall sample bias is hard to assess, as the West South Central division – which includes Oklahoma and Texas – is generally a low-cost wind region, while the East North Central and Pacific divisions tend to be high-cost regions (the New England PPA total is small enough in MW terms to ignore for this purpose). For example, Figure 2, which shows the levelized PPA price of each contract within the LBNL sample,[7] reveals that contracts in the East North Central region, and particularly in the Pacific

[5] The LBNL wind PPA price sample is compiled from a variety of sources, including regulatory filings with the Energy Information Administration ("EIA"), the Federal Energy Regulatory Commission ("FERC"), and state public utilities commissions.

[6] Underrepresentation in the West South Central division is largely attributable to Texas, where projects located within the footprint of the Electric Reliability Council of Texas ("ERCOT") – i.e., the grid operator for most of the state – are not subject to Federal Energy Regulatory Commission ("FERC") reporting requirements (filings with FERC are a principal source of PPA price data).

[7] Each circle in Figure 2 represents the levelized PPA price (y-axis) of a single wind contract, plotted along the x-axis by the date on which that PPA was signed. PPA prices are levelized over the full duration of each contract using a 7% real discount rate. The area of each circle represents the size (in MW) of the contract; several

region, tend to be above the dashed polynomial trend line for the full sample, while contracts from the West North Central region tend to fall below this overall trend line. From a national perspective, it is possible that underrepresentation within these three regions is offsetting to some extent.

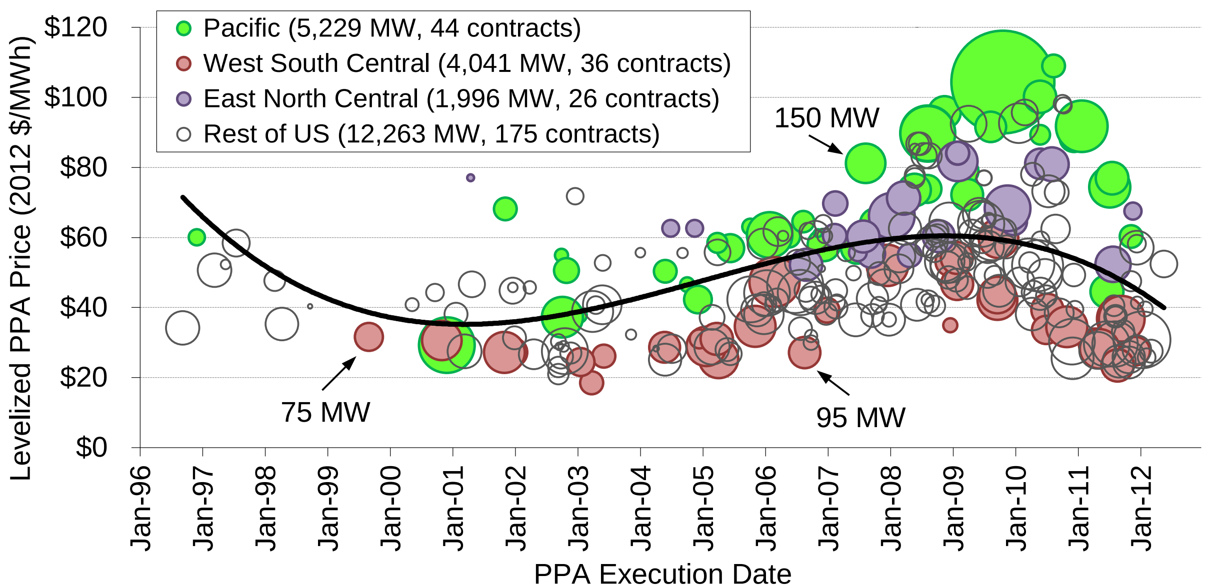


Figure 2. Levelized Wind Power PPA Prices by PPA Execution Date

The mean PPA contract duration in the LBNL sample is 20.2 years (20.7 years on a capacity-weighted average basis), while the median is 20 years. Twenty-year contracts make up 58% of all PPAs (and 53% of all capacity) in the LBNL sample, followed by twenty-five-year contracts at 19% (26% of capacity), and then 15-year contracts at 9% (8% of capacity). In total, more than three quarters of all wind power capacity in the LBNL sample is selling power through PPAs that are twenty years or longer in duration.

In all cases, PPAs within the LBNL sample convey all energy, capacity, and renewable energy credits ("RECs") generated by the project (or at least that portion of the project represented by the PPA) to the buyer.[8] As such, these PPA prices represent the entire revenue stream earned by the project on a post-government-incentive basis. In instances where government incentives – such as, but not limited to, the 10-year PTC or the Section 1603 Treasury grant – have been awarded to the project, the PPA price is presumed to reflect the receipt of any such incentives.

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benchmarks are provided for reference. The dashed 2nd-order polynomial line represents the best fit time trend for the full LBNL PPA price sample, and reflects that wind PPA prices have fallen since 2009, after having previously risen from 2002 through 2009.

[8] Energy refers to the electricity generated by the project, capacity refers to the project's contribution towards meeting peak demand (which is explicitly valued in some markets), and renewable energy credits, or RECs, represent the environmental attributes of wind power. RECs can be stripped out and sold separately from a wind project's energy and/or capacity. By design, however, all of the projects within the LBNL PPA sample sell RECs on a "bundled" basis along with energy and capacity, such that the PPA price reflects the full post-government-incentive amount of revenue received by the project.

In other words, the amount of revenue required by the project (through the PPA price) is assumed to have been reduced due to the government incentives provided.

By definition, all of the PPAs in the LBNL sample feature prices that are contractually locked in and that were known in advance (i.e., fixed) at the time each contract was signed. In 44% of the LBNL sample (48% in capacity terms), these prices remain constant in nominal dollar terms over the life of the contract (i.e., each MWh of wind generation is sold for exactly the same price over the entire contract term). Another 11% (of capacity) features pricing terms that do not escalate from year to year, but that do vary diurnally (e.g., depending on whether electricity is generated during on-peak or off-peak hours) and/or seasonally within each year. In total, then, 59% of the LBNL contract sample features prices that do not escalate in nominal dollars over time (which means that they actually *decline* in real dollar terms over time).

Another 38% (in capacity terms) of the LBNL sample is sold under PPA prices that do escalate (in nominal dollar terms) on an annual basis.[9] Escalation rates vary from contract to contract, and are not always uniform from year to year over the contract term, but in general average around 2.4% going forward. In other words, in most cases, nominal escalation rates are intended primarily to keep pace with anticipated inflation, which means that prices do not change by much in real dollar terms. Unlike gas-fired generation, wind power can offer this type of PPA price stability because much of the cost in a wind power project is up-front capital cost; operating costs are relatively low, because the fuel itself is free.

Figure 3 shows the generation-weighted average wind PPA price (expressed in both nominal and real 2012 $/MWh) from the entire LBNL sample, extending both back in time and into the future.[10] These average prices are overlaid on top of an area graph showing the combined capacity of the PPA sample at any given point in time. The maximum contract sample is naturally achieved in 2012, and then declines in the future as contracts expire, causing projects to drop out of the sample, at first gradually and then more rapidly as the years progress. As this happens, the average wind price becomes more volatile in later years, as the small remaining contract sample becomes increasingly dominated by a number of large projects. For example, the sharp drop in average PPA pricing in 2036 is caused by more than 1 GW of relatively high-priced wind power in California dropping out of the sample at that time.

[9] The remaining 3% (in capacity terms) of the LBNL sample features PPA prices that both escalate and de-escalate (or vice versa) annually over time.

[10] Generation-weighted average prices are calculated based on actual generation historically (where available) and assuming that historical capacity factors hold into the future. For those wind projects that lack sufficient operating history to enable the calculation of an empirical capacity factor, generation-based weightings were derived from some combination of generation estimates from either within the PPA itself or externally, along with use of the author's judgment where necessary. Although capacity-weighted average prices are more straightforward to calculate (given that the rated capacity of each project is known with certainty), generation-weighted averages provide a truer measure of the average cost of wind energy across the LBNL sample.

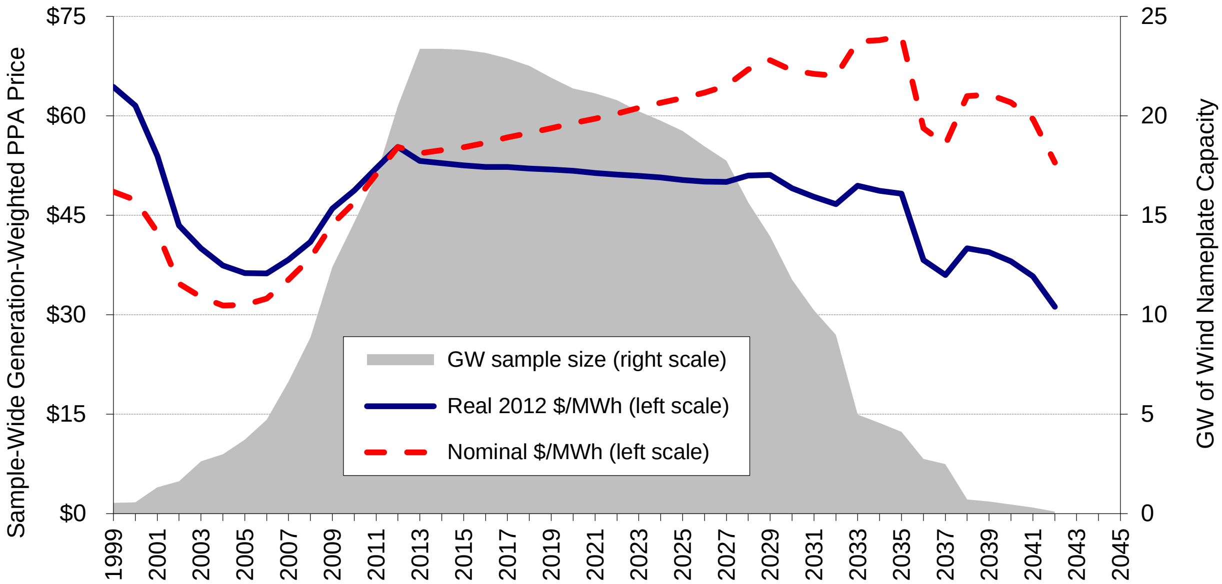


Figure 3. Generation-Weighted Average Wind PPA Price Over Time vs. Sample Size

Focusing on just the future period through 2031, during which sample size remains relatively robust above 10 GW, reveals that average wind power pricing holds relatively steady during this period. In nominal dollar terms, the average price for the full LBNL sample escalates by just 1.1%/year on average. In real 2012 dollar terms, the average price actually *declines* slightly by 0.6%/year on average,[11] hovering right around $50/MWh. In other words, buyers of the wind power in the LBNL sample can rest assured that, on average and in real dollar terms, wind power will cost them no more (and even slightly less) in 2031 than it does today.

2.2 Natural Gas Prices Are Historically Low, But Difficult to Lock In

Though they have historically been quite volatile, natural gas prices are currently close to 10-year lows, and are expected by many to remain relatively low in the years ahead as continued shale gas development provides ample domestic supply. In contrast to wind power prices, however – which, as demonstrated in the previous section, can be locked in for long periods of time with relative stability – natural gas prices are difficult to lock in for any significant duration. In large part for this reason, gas-fired generation is rarely sold on a fixed-price basis, particularly over longer terms. Instead, gas-fired generation – whether owned by a utility or purchased through a PPA – is most often variable-priced in nature, thereby requiring the utility to hedge fuel prices in order to replicate any degree of price stability. Though short-term gas price risk can be effectively hedged using conventional instruments like futures, options, and bilateral physical supply contracts, this section demonstrates that these instruments come up short when one tries to lock in prices over longer terms – e.g., greater than five or ten years. It is over these longer-term periods where inherently stable-priced generation options like wind power hold a rather unique competitive advantage.

[11] Conversions between nominal and real dollars are made using the actual historical GDP deflator (for historical conversions) or the EIA's latest projection (in EIA 2012a) of the GDP deflator going forward (for future conversions).

The solid blue line in Figure 4 shows monthly spot gas prices at the Henry Hub in Louisiana (i.e., the delivery point for NYMEX natural gas futures contracts) going back to January 2002. After experiencing unprecedented volatility – marked by two extreme price spikes to more than $12/MMBtu – natural gas prices fell sharply during the recession of 2008 and 2009, and in early 2012 broke through 10-year lows below $2/MMBtu. Though prices have since recovered somewhat, the decade-low gas prices seen during much of 2011 and 2012 are behind much of the fuel-switching currently happening in the power sector.

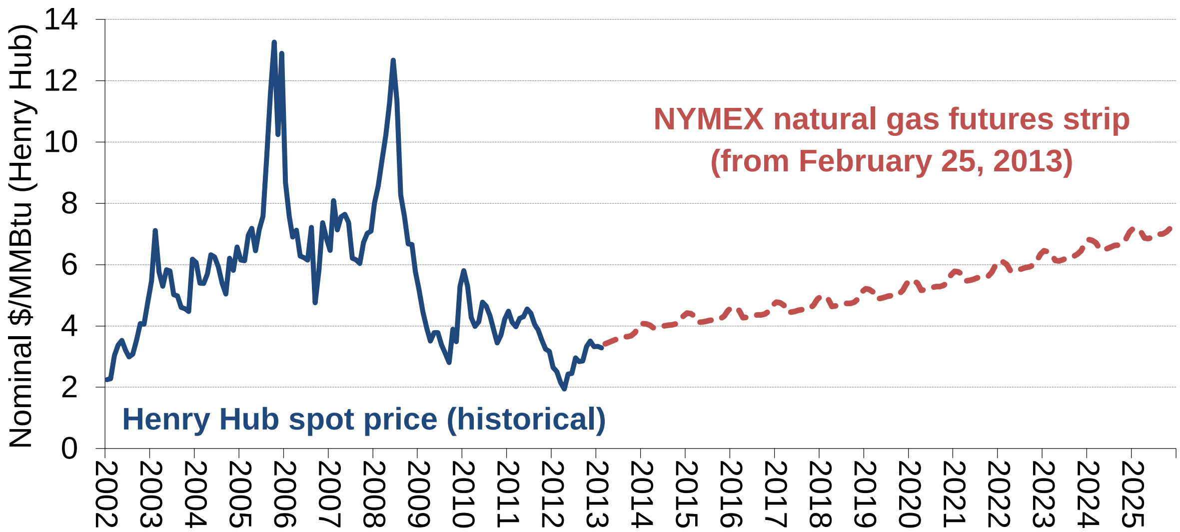


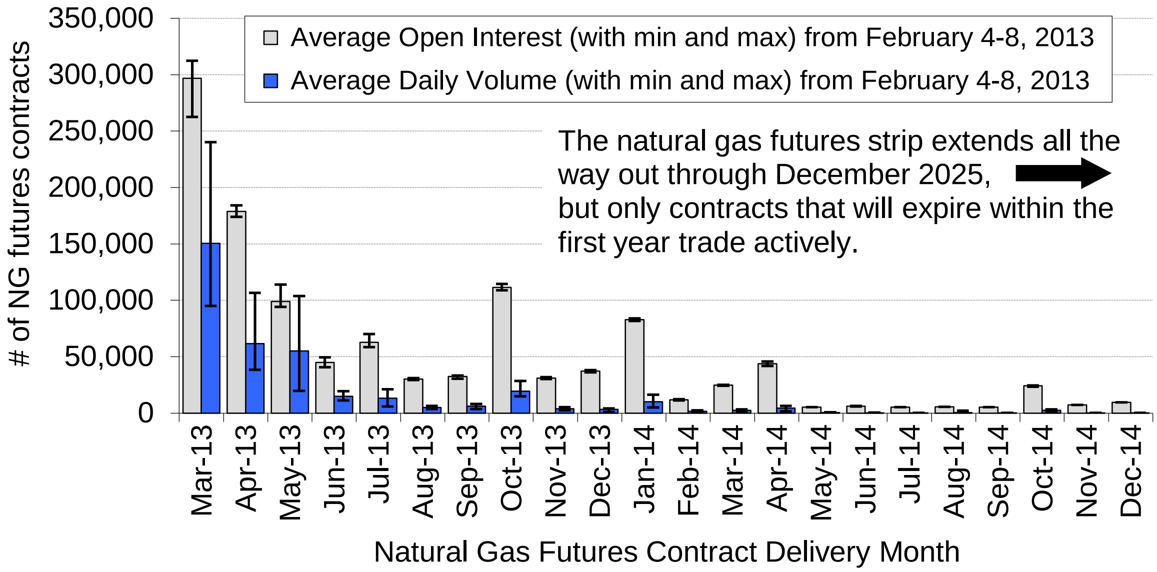
Figure 4. Historical Henry Hub Natural Gas Prices and NYMEX Gas Futures Strip

It's not possible to lock in these historic low prices out into the future, however. The red dashed line in Figure 4 shows the price of the NYMEX natural gas "futures strip" or "forward curve" from February 25, 2013. This futures strip represents the natural gas prices that, as of February 25, could be locked in for delivery in each future month through December 2025, simply by buying futures contracts. While current spot prices are just above $3/MMBtu, the fact that the futures strip is upward-sloping means that this low price cannot be locked in for any length of time. In other words, participants in the futures market expect (on average) spot gas prices to rise from current levels in the coming years – e.g., to $4/MMBtu by mid-2014, $5/MMBtu by 2019, and $6/MMBtu by 2022 – and are therefore unwilling to sell futures contracts at today's low spot prices.[12]

Even if today's low price levels were reflected in the futures strip and therefore available for purchase, it could still be difficult to lock them in over long terms (particularly for large volumes), because the futures market – though very liquid for the first few months of listed contracts– is relatively illiquid over longer terms. Figure 5 shows the average daily trading volume and open interest for the first 22 months of the NYMEX gas futures strip (i.e., shown

[12] One could buy a series of "in the money" call options on gas futures contracts with strike prices set to equal today's spot price (i.e., below the futures strip). Such a string of options would, in fact, grant the right to buy gas in the future at today's spot price. But the "intrinsic value" (i.e., the difference between the futures contract price and the options strike price) embedded in the options premiums would negate the below-market strike price, leaving the buyer no better off than the prices reflected in the upward-sloping futures strip.

only through the December 2014 contract, not all the way out to December 2025) over a representative 1-week period in February 2013.[13] Though natural gas contracts are currently listed out through December 2025, both volume and open interest dry up within a year or so. This makes it difficult to trade any sort of volume over any length of time.



Source: CME Group

Figure 5. Average Volume and Open Interest in NYMEX Gas Futures Contracts

The futures market is, of course, not the only game in town. Bilateral contracts for physical gas supply are also available, but have their own set of issues. Physical supply contracts tend to be less-liquid than the futures market over shorter terms, and similarly illiquid, or even less liquid, over longer terms. In general, the market does not have an appetite for fixed-price physical supply contracts that exceed 10 years (and even 10-year deals are rare), due to the inherent risk of locking in a price for a commodity that has historically been quite volatile (PSCo 2011). Counterparty credit or default risk is a major issue – much more so than with an organized exchange like the NYMEX, where the exchange itself, backed by the combined credit of its members, is the counterparty to every trade (PSCo 2011). Finally, pricing of physical supply contracts is unlikely to diverge significantly from the basis-adjusted NYMEX futures strip[14] – i.e., market price expectations do not vary depending on the type of instrument being traded – which, again, means that it will be difficult or impossible to lock in current low prices going forward for any length of time, due to the upward-sloping nature of the forward curve.

[13] Open interest is defined as the number of outstanding futures contracts for any given delivery month that have not yet been closed out by an offsetting transaction or otherwise fulfilled by delivery. As such, open interest represents a measure of potential future volume or liquidity.

[14] For example, in December 2010, the Colorado Public Utilities Commission approved a 10-year, fixed price (with annual escalation) bilateral physical gas supply contract between the Public Service Company of Colorado ("PSCo") and Anadarko, with deliveries to begin in 2012. Not surprisingly, contract pricing closely resembles the basis-adjusted NYMEX futures strip at the time. This contract has received quite a bit of attention in the industry, due to its uncommonly long 10-year duration.

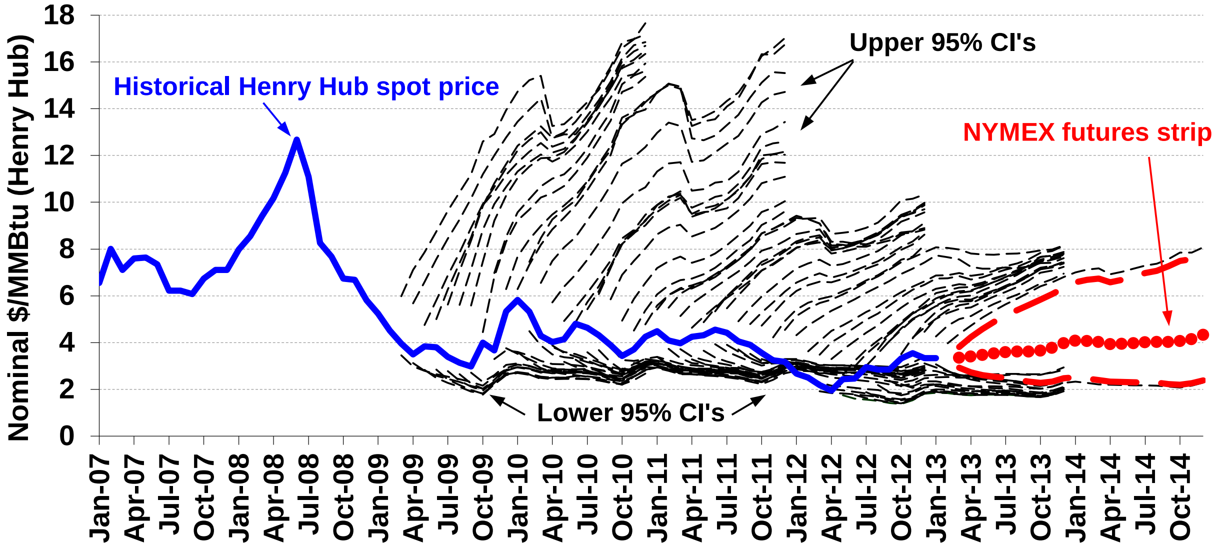
Given the apparent difficulty of locking in today's low prices over longer terms, one might reasonably question the prudence of even trying to do so. If the U.S. shale gas resource proves to be as robust and economically recoverable as is currently believed, then there could be a surplus of supply for many years to come, helping to keep a lid on natural gas prices over longer terms. Indeed, this is seemingly the conclusion reached by utility regulators in some states, who have been tightening restrictions on utility hedging of natural gas prices, based on the belief that the cost of such hedging programs is likely to outweigh any benefit in a low-volatility, low-gas-price environment (Ryan and Lieberman 2012).[15]

Ultimately, only time will tell whether hedging at this particular moment in time would have been a *profitable* decision. This ever-present uncertainty, however, does not mean that hedging is not currently a *prudent* decision. Taking the view that hedging – and in particular long-term hedging – is not as important now, with gas prices just coming off of historical lows, as it may have been in the past when prices were higher, ignores the highly skewed nature of gas price risk at the moment. For example, back in April 2012 when spot gas prices were hovering around $2/MMBtu – i.e., not terribly far from the absolute floor price of zero – the risk that prices would rise by more than $2/MMBtu was almost infinitely greater than the risk that prices would fall by more than $2/MMBtu. Although spot prices have since risen to above $3/MMBtu, price risk remains skewed to the upside.

This skew is evident in Figure 6, which is compiled from the EIA's monthly Short-Term Energy Outlook ("STEO") series (EIA 2009-2013). Each month, in the *Market Prices and Uncertainty Report* that accompanies the STEO, the EIA uses information (mostly about implied volatility) embedded within the market price of options on natural gas futures contracts to calculate the 95% confidence intervals around the price of those future contracts. These confidence intervals bound the range of prices within which the market expects (with 95% confidence) that the futures contract will ultimately expire. When applied to each successive contract month along the futures strip,[16] these 95% confidence intervals form a "cone" around the mean price expectations reflected in the futures strip; this cone tends to widen out over time because price uncertainty increases with the time to contract expiration. Figure 5 simply compiles the 95% confidence interval cones from each monthly edition of the STEO going back to early 2009, and presents them all on a single graph (EIA 2009-2013).

[15] These restrictions seem to pertain mostly to active short-term hedging programs, such as those that use options contracts to create guaranteed price caps or to lock in a range of future gas prices for a few months. Conversely, regulators in several states have taken steps to encourage the use of long-term natural gas contracts as a way to lock in current low gas prices over the long term (for example, see footnote 14 and Costello (2012)).

[16] Although the natural gas futures strip extends out for a maximum of 156 months (i.e., 13 years), the EIA only calculates these confidence intervals for, at most, the first 24 months of the strip.



Source: EIA 2009-2013

Figure 6. History of 95% Confidence Intervals Around Natural Gas Futures Strip

Going back to February 2009, the lower 95% confidence intervals have rarely fallen below \$2/MMBtu – despite relatively low spot prices over this entire period – reflecting the physical reality of a floor price.[17] Even in April 2012, when spot gas prices broke below \$2/MMBtu, the lower 95% confidence interval never fell below \$1.38/MMBtu, and averaged \$1.70/MMBtu out through the December 2013 contract. In other words, with spot prices as low as they were at the time, there was recognition that they simply could not fall much further before hitting physical limits, making the gas price bet almost uni-directional. The upper 95% confidence intervals, meanwhile, have varied significantly over time, initially rising above \$16/MMBtu (no doubt reflecting the recent memory of the mid-2008 price spike to more than \$12/MMBtu), but over time diminishing to the point where the most recent STEO (in February 2013) shows the upper bound for the December 2014 futures contract to be just below \$8/MMBtu.

Despite the fact that the upper confidence intervals have narrowed as the market has grown increasingly confident in the promise of shale gas development, the overall range remains skewed to the upside. For example, in February 2013, the market had 95% confidence that the December 2014 NYMEX futures contract would eventually expire somewhere between \$3.50/MMBtu above and \$1.95/MMBtu below the then-current contract price of \$4.32/MMBtu (the red dashed lines on the right side of Figure 6 represent the 95% confidence intervals from the February 2013 STEO, which was the latest edition available at the time of writing). This represents a 1.8:1 skew – i.e., the market believed, with 95% confidence, that prices could potentially rise by 1.8 times as much as they could fall by December 2014.

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[17] The absolute floor price is, of course, zero, but in practice there will be some production-cost-related floor price above zero, below which it does not make economic sense to produce and market the gas. Where exactly this floor price lies will vary by shale play, and will also depend on the extent to which the marketed "dry gas" (i.e., methane) is largely a byproduct (with very low marginal cost) of the extraction of either more-valuable "natural gas liquids" (i.e., ethane, propane, and butane) or shale oil.

To summarize, with gas prices as low as they are, and with gas price risk heavily skewed to the upside, it should theoretically be an opportune time to hedge. The directional bet has been almost one-sided, and – to use a well-known analogy – the best time to buy flood insurance is before the water starts rising. The water has already started rising, however, in the sense that the futures strip is upward-sloping. In other words, even though spot gas prices are historically low, one can't lock in these low prices going forward – or at least not without paying a hefty premium in the options market to do so. Even if today's low prices were available through the futures strip, the futures market is just not very liquid beyond a few years out, making it hard to trade any sort of volume over longer terms. Bilateral physical supply contracts are available, but only over the short-to-mid-term (10-year contracts are a rarity), and impose significant counterparty default risk due to the perils inherent in fixing the price of a notoriously volatile commodity. Moreover, the pricing of physical supply contracts will not differ significantly from the upward-sloping futures curve. Finally, even if it were easier to hedge, regulators have been restricting the budgets of utility gas hedging programs, ultimately leaving ratepayers increasingly exposed to unanticipated natural gas price increases.

In light of this current situation, viewing wind power as a long-term fuel price hedge would seem to be as appropriate now as it has ever been, despite prevailing low gas prices. In fact, it may be even *more* appropriate now, given the almost one-sided nature of the gas bet. Whether or not wind can provide this long-term hedge in a cost-effective manner, however, is a separate question altogether – this question is explored in the remainder of this article.

3. Establishing an Appropriate Price Comparison Between Wind and Gas

3.1 Simplifying Assumptions

The rest of this article explores the question of whether wind can provide a cost-effective long-term natural gas price hedge by comparing PPA prices from actual wind projects in the LBNL sample to a range of long-term natural gas fuel cost projections. Implicit in this comparison are a handful of simplifying assumptions, three of which handicap and two of which advantage wind relative to gas.

The first simplifying assumption is that wind serves only as a natural gas "fuel saver" – i.e., wind serves only as an energy resource (and *not* as a capacity resource), and each MWh of wind generation displaces one full MWh of gas-fired generation. [18] This assumption effectively assigns zero value to the capacity portion of the wind PPA price, thereby attributing the full PPA price to the energy and REC components (though, as discussed below, the REC component is also zeroed out in this article to further simplify the analysis). In reality, wind projects do provide some capacity value, though the amount is often relatively small (a general rule of thumb is that a wind project's *capacity credit* – which when multiplied by the cost of capacity yields capacity value – is likely to be less than its capacity factor), will vary from region to region (and even from project to project within a region), will generally decline as wind power penetration increases, and depends on how capacity credit is calculated (Rogers and Porter 2011). As such, treating wind as merely a natural gas fuel saver, and therefore comparing wind PPA prices to only the fuel costs of gas-fired generation, handicaps wind relative to gas to some extent (i.e., by the amount of capacity value that wind does, in fact, provide). That said, there is evidence that some utilities think of wind in exactly this manner – i.e., as a fuel saver, with no credit given to its capacity value[19] – and that is also the conservative approach taken here.

A second simplifying assumption that handicaps wind (and that was alluded to above) is that no credit is given for wind's relative environmental benefits, including the value of avoided criteria pollutant and greenhouse gas emissions. Because these benefits can at least loosely be

[18] Although wind generation displaces primarily gas-fired generation most of the time throughout most of the U.S., there are times (e.g., during off-peak periods most notably) in certain markets when wind generation displaces coal-fired or other forms of generation. As such, the sole focus here on gas-fired generation is a simplification.

[19] For example, a representative of the Public Service Company of Colorado – owned by Xcel Energy, which at the end of 2011 had the most wind power capacity on its system of any utility in the U.S. (AWEA 2012a) – recently testified before the Colorado Public Utilities Commission regarding the utility's 25-year contract with the 200 MW Limon II wind project, noting that "The wind generation is a source of fuel or energy, it's not a source of capacity" (Haeger 2011), and that "since wind is really just an energy resource and not a capacity resource, we treat it like a fuel or fuel substitute" (Haeger 2012). He went on to note that "When Public Service plans its system, we make sure we have adequate generation [i.e., capacity] resources to meet the highest load days. Once we have the capacity resources in place, we then focus on generating energy at the lowest most stable cost….wind energy is a direct substitute for gas-fired generation so one can simply compare the cost of wind to the energy cost component of more traditional generation like gas-fired generation….Since the generators necessary to burn natural gas or other fossil fuels have already or will be acquired to meet reliability needs, the only difference between using wind as a fuel compared to natural gas is the cost of the two fuels or energy sources" (Haeger 2012).

associated with the bundled REC component of the PPA price, the effect of this simplifying assumption is to assign zero value to the REC component, thereby attributing the full wind PPA price to just the energy component (since, as described above, the capacity component is also assumed to hold zero value). In combination, then, these first two simplifying assumptions effectively equate the wind PPA price with just the cost of generating (or purchasing) electricity, which can then be compared to just the variable cost of generating gas-fired electricity.

Equating the variable cost of generating gas-fired electricity with just natural gas fuel costs is a third simplifying assumption. In reality, gas-fired generators must also incur non-fuel operations and maintenance ("O&M") costs in order to generate electricity, and wind – acting as a fuel saver – should receive some credit for offsetting any variable portion of these non-fuel O&M costs. The non-fuel variable O&M costs of gas-fired generation are relatively small, however – e.g., on the order of $3/MWh for an advanced combined-cycle gas turbine (EIA 2010). Furthermore, any wind-enabled reduction in these costs could potentially be offset, to some extent, by correspondingly greater wear and tear on gas-fired power plants from the increased cycling required to balance wind power's natural variability. Lacking clear insight on where the true balance of these opposing influences lies, this analysis simply ignores any non-fuel O&M cost savings provided by wind, and focuses instead on just avoided fuel costs.

The fourth and fifth simplifying assumptions are to ignore integration and transmission costs, both of which would penalize wind relative to gas on average were they included. Integration costs, however, have been shown to be relatively low and area-specific (Wiser and Bolinger 2012), and there is a growing recognition among analysts that they may not even be readily quantifiable or unique to variable renewable generators like wind and solar (Milligan et al. 2011). Transmission costs, meanwhile, will vary considerably from project to project, and in some regions will not be borne by either the wind buyer or seller, depending on how transmission cost allocation is handled.[20] For these reasons, both integration and transmission costs are omitted from this analysis.

In short, this comparison of wind versus gas is not intended to be a full analysis from a societal perspective. It is also not the only, or perhaps even the most appropriate, way to structure such a comparison.[21] Instead, it is a simple comparison between actual wind PPA prices and projected natural gas fuel costs, assuming that wind serves only as a natural gas fuel saver. Though admittedly simplistic, this approach is not entirely an academic exercise, as again there is

[20] For example, within ERCOT, transmission costs are socialized across all electricity ratepayers, rather than being paid by either the seller or buyer of the power itself. Note that this fifth simplifying assumption refers primarily to transmission network upgrades or new construction needed to accommodate wind power *in general*. In contrast, the costs of so-called "gen-tie" lines built by specific wind developers in order to interconnect specific projects to the transmission grid are, in general, borne by the project developer or power seller, and are therefore presumably reflected in the wind PPA price.

[21] For example, rather than taking this article's "bottom up" approach of assuming that wind is merely a natural gas fuel saver (i.e., with no capacity value) and therefore comparing wind PPA prices solely to natural gas fuel costs, one could instead take more of a "top-down" approach by comparing wind PPA prices to the all-in costs of building new gas-fired generation. This latter approach, however, would require just as many simplifying assumptions (e.g., about the capacity value of wind relative to gas, about relative transmission and integration costs, etc.) as have been employed here in order to place wind and gas on a comparable footing. In other words, these two different approaches would eventually arrive at much the same basic comparison, despite starting from opposite ends of the spectrum.

evidence that some utilities think about the comparison between wind and gas in a similar manner (e.g., see footnote 19). Future research might seek to quantify each of the additional cost variables discussed above in order to elucidate further comparisons.

3.2 Fuel Cost Projections

While the wind PPA prices used in the comparison come from the LBNL sample described in Section 2.1, long-term natural gas fuel cost projections are sourced exclusively from the EIA, which is the statistical and analytical agency within the U.S. Department of Energy ("DOE"). Over the past two years, the EIA has published natural gas fuel cost projections associated with at least twenty different future scenarios, both as part of its regular *Annual Energy Outlook* ("AEO") series (EIA 2012a, 2012b, 2011) and also in response to a specific request from the DOE's Office of Fossil Energy, which in August 2011 asked the EIA to look into the impact of future LNG exports on domestic energy markets (EIA 2012c). These twenty different scenarios are categorized in Table 2 and graphed in Figure 7.[22]

Specifically, Table 2 shows that fifteen of the twenty fuel cost projections of interest originate from analysis either within AEO 2011 itself (e.g., the Reference, High EUR, and Low EUR cases) or using the same version of the National Energy Modeling System ("NEMS") as was used for AEO 2011 (e.g., the 12 different LNG export scenarios that were requested by the DOE's Office of Fossil Energy). A gas well's estimated ultimate recovery ("EUR") is defined as its cumulative production over a 30-year life using current technology and without regard to economic considerations; the High and Low EUR scenarios (in both AEO 2011 and AEO 2012) consider 50% greater or lesser EUR per shale well than in the Reference case. Technically recoverable resources ("TRR"), which are unproved shale resources that are estimated to be technically recoverable using current technology and without regard to economic considerations, also correspondingly vary by +/-50% in these scenarios. The lone exception is AEO 2012's High TRR scenario, which assumes that tighter shale well spacing allows for even greater TRR (1,091 Tcf) than would be implied by an EUR that is 50% greater than in the Reference case. Finally, four export scenarios – varying in both the steady-state export volume (either 6 or 12 Bcf/day[23]) as well as the ramp rate to get to steady state (either 1 or 3 Bcf/day/year) – are layered on top of three different underlying scenarios (Reference, High EUR, Low EUR), for a total of 12 export scenarios altogether.

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[22] EIA gas price projections are used for this analysis because they are freely available, well-documented, and cover a wide range of future scenarios. The EIA's own comparison of its *AEO 2012* reference case natural gas price projection (for gas delivered to electricity generators) to two different private sector forecasts found that its own projection fell below the two other forecasts in the year 2015, and in between the two other forecasts in the years 2025 and 2035 (EIA 2012b).

[23] In comparison, footnote 1 earlier notes that as of January 30, 2013, twenty-three applications to build LNG export terminals – with a combined export capacity of more than 29 Bcf/day – had been submitted to the U.S. Department of Energy. The likelihood of all of these export facilities, or even a significant subset of them, being approved and built is rather low, however (Krauss 2013).

Table 2. Characterization of Recent EIA Natural Gas Scenarios

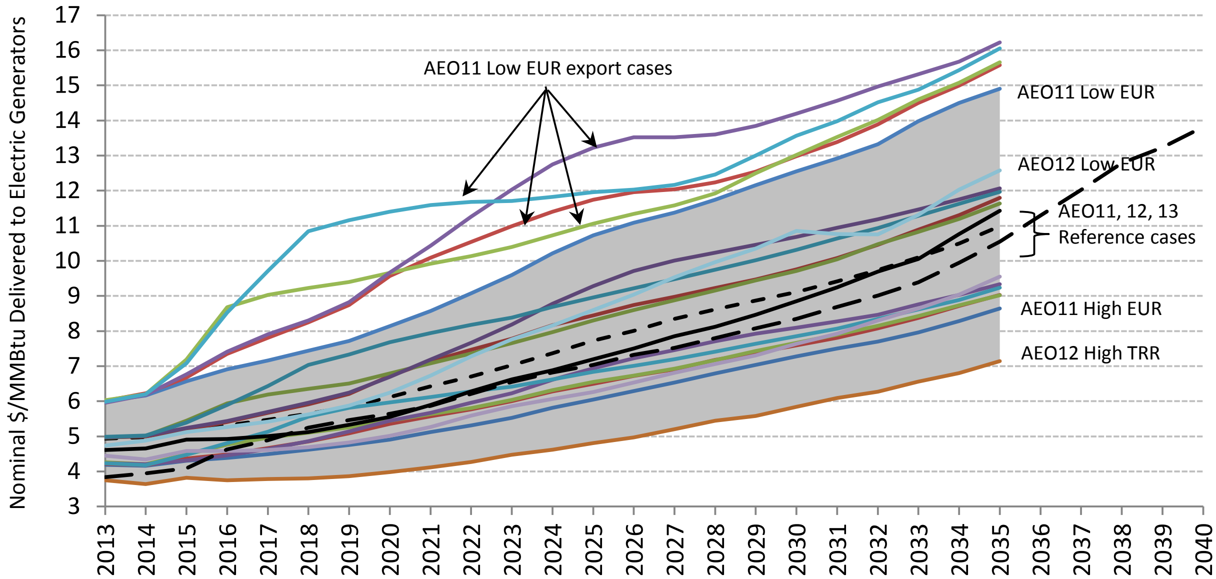
NEMS Modeling Platform	Scenario Name	EUR per shale well (% diff from reference)	Unproved Shale TRR (Tcf)	LNG Export Volume (Bcf/day)	LNG Export Phase-In (Bcf/day/year)
AEO 2013	Reference (early release)	N/A	543	N/A	N/A
AEO 2012	Reference	N/A	482	N/A	N/A
AEO 2012	High EUR	+50%	723	N/A	N/A
AEO 2012	Low EUR	-50%	241	N/A	N/A
AEO 2012	High TRR*	+50%	1,091	N/A	N/A
AEO 2011	Reference	N/A	827	N/A	N/A
AEO 2011	Reference, Low/Slow Export	0%	827	6	1
AEO 2011	Reference, Low/Rapid Export	0%	827	6	3
AEO 2011	Reference, High/Slow Export	0%	827	12	1
AEO 2011	Reference, High/Rapid Export	0%	827	12	3
AEO 2011	High EUR	+50%	1,230	N/A	N/A
AEO 2011	High EUR, Low/Slow Export	+50%	1,230	6	1
AEO 2011	High EUR, Low/Rapid Export	+50%	1,230	6	3
AEO 2011	High EUR, High/Slow Export	+50%	1,230	12	1
AEO 2011	High EUR, High/Rapid Export	+50%	1,230	12	3
AEO 2011	Low EUR	-50%	423	N/A	N/A
AEO 2011	Low EUR, Low/Slow Export	-50%	423	6	1
AEO 2011	Low EUR, Low/Rapid Export	-50%	423	6	3
AEO 2011	Low EUR, High/Slow Export	-50%	423	12	1
AEO 2011	Low EUR, High/Rapid Export	-50%	423	12	3

*The High TRR case assumes tighter well spacing than the other AEO12 scenarios, which is why the unproved TRR increases even though the EUR per well remains 50% above the reference case.
Source: EIA 2012a, EIA 2012b, EIA 2012c, EIA 2011

Figure 7 shows the resulting projected fuel costs of natural gas delivered to electricity generators across all twenty of these scenarios for the U.S. as a whole.[24] Due to the sheer volume of overlapping projections, only eleven of the twenty scenarios are labeled in Figure 7. The majority of projections are loosely bound by the AEO11 High EUR scenario on the low end and the AEO12 Low EUR scenario on the high end; the three Reference case scenarios all fall within this range.[25] A bit farther afield are the AEO12 High TRR and AEO11 Low EUR scenarios on the low and high ends, respectively. Finally, the four AEO11 Low EUR export scenarios result in the highest fuel cost projections.

[24] Natural gas prices and price projections can vary substantially by region within the U.S. (as can wind PPA prices – see Figure 2 earlier). In order to simplify the comparison as much as possible, however, this article employs only average gas price projections for the U.S. as a whole (and compares them to average wind PPA prices across the entire LBNL sample).
[25] Though not pictured in Figure 7, it is perhaps worth noting that the AEO13 early release reference case gas price projection for the Henry Hub lies *below* where the NYMEX Henry Hub futures strip was trading at the time the projection was made in late October 2012 (it also lies below where the futures strip has traded ever since, up to the time of writing). In other words, it has not been possible to lock in future natural gas prices at levels projected by the EIA in its AEO13 early release reference case. Past work has highlighted this discrepancy between long-term model-based gas price projections and futures market prices as a source of potential bias against fuel-free renewable generation in favor of gas-fired generation (Bolinger et al. 2006).

These four AEO11 Low EUR export scenarios were subsequently found to be unlikely during the second phase of the DOE Office of Fossil Energy's LNG export study (Montgomery et al. 2012). Specifically, under Low EUR conditions, domestic natural gas prices are projected to be high enough such that LNG export prices are not competitive on the world market (once the costs of liquefaction, transportation, and regasification are added). As such, U.S. LNG exports are unlikely to occur under the Low EUR scenarios, which, in turn means that the domestic fuel cost projections for these four scenarios are spurious. For this reason, these four export scenarios are not considered further in this analysis; this exclusion is symbolized by their omission from the shaded area in Figure 7. Only the fuel cost projections within this shaded area will be compared to wind PPA prices in the next section.



Source: EIA 2012a, EIA 2012b, EIA 2012c, EIA 2011

Figure 7. Projected Natural Gas Prices Delivered to Electricity Generators, Total U.S.

4. Results: Assessing the Cost-Effectiveness of Wind as a Long-Term Price Hedge

Figure 8 presents the comparison between the full LBNL wind PPA price sample described in Section 2.1 and the range of projected natural gas fuel costs described in Section 3.2. To reduce visual clutter, Figure 8 (as well as Figure 9) shows only the *range* of fuel cost projections, as denoted by the shaded area (hereafter referred to as "the cone of uncertainty"). Previously presented in Figure 7 in nominal $/MMBtu terms, this cone of uncertainty has been translated into $/MWh terms in Figure 8, using the average heat rates implied by each individual scenario's NEMS modeling output.[26] Overlaid on top of the cone of uncertainty are the three reference case scenarios from AEO11, AEO12, and AEO13 early release. The red line with circle markers represents actual historical gas prices delivered to generators (on an average nationwide basis), and the solid blue line represents the generation-weighted average wind PPA price from among the entire LBNL sample of more than 23 GW of wind capacity built in the U.S. since 1997.

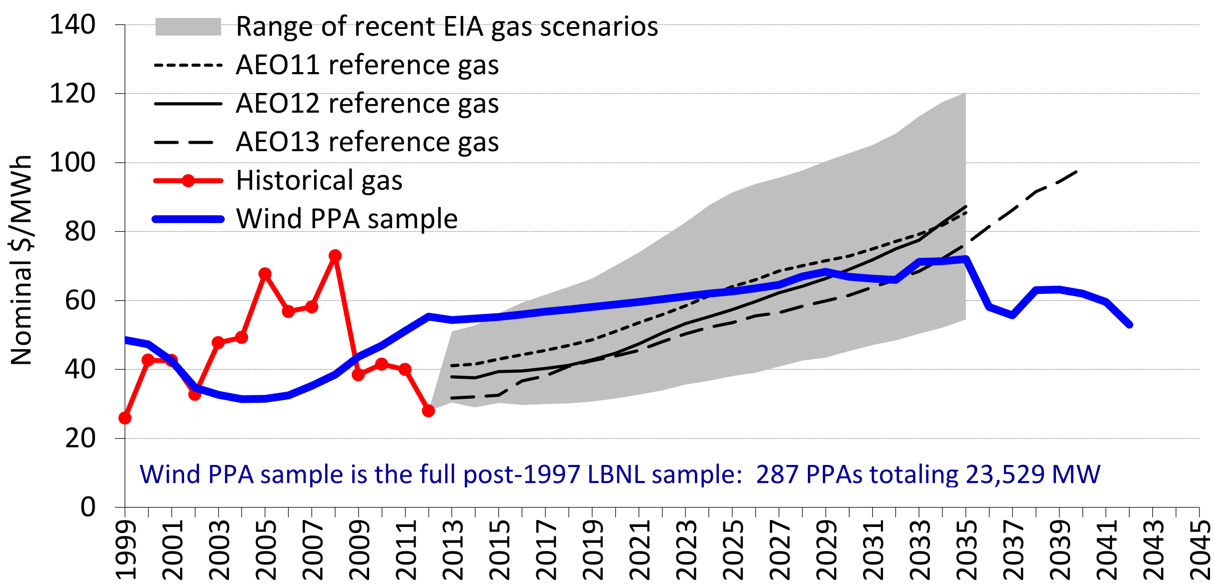


Figure 8. Comparison of Full Wind PPA Sample to Projected Range of Natural Gas Prices

As shown, the generation-weighted average wind PPA price from within the entire LBNL sample was significantly *below* gas-fired generators' fuel costs from 2003-2008. Ever since the sharp drop in natural gas prices in 2009, however, the average wind PPA price has been above-market, and – looking ahead – it lies above the three reference case fuel cost projections until 2025 (AEO11), 2030 (AEO12), and 2032 (AEO13 early release). Thus, if natural gas prices actually end up following any of these three reference case projections into the future, then the wind contracts in the LBNL sample will, on average nationwide, be above market (as defined here; see Section 3.1 for simplifying assumptions) until the crossover years noted.

[26] Using implied *average* heat rates to convert from $/MMBtu to $/MWh is likely a conservative practice, given that wind is more likely to displace less-efficient gas-fired units with higher heat rates on the margin.

Focusing instead on the cone of uncertainty, however, the average wind PPA price shown in Figure 8 penetrates the cone in 2015, and thereafter serves as a hedge against many of the higher-priced fuel cost projections modeled by the EIA, with the degree of potential price protection increasing over time. Hence, if minimizing exposure to these potentially significant long-term gas price increases is desirable, then Figure 8 suggests that wind power could be an effective tool to help achieve that goal.

While Figure 8 represents the entire LBNL sample (including wind projects built as far back as 1998), Figure 9 focuses on just the most recent projects in our sample – specifically, those that signed PPAs in 2011 or 2012 (and most of which were built in 2012).[27] As shown earlier in Figure 2, wind PPA prices have fallen considerably in recent years (Wiser and Bolinger 2012), driven by a combination of installed cost reductions (Bolinger and Wiser 2012) and performance improvements (Wiser et al. 2012). As such, this recent sub-sample of contracts likely better reflects current wind PPA pricing (at least on a national average basis), which means that Figure 9 provides a more accurate national representation of the choice between wind and gas facing resource planners today. The downside of restricting the sample to just the most recent contracts, of course, is that sample size is reduced considerably, to just 3.7 GW. The regional composition of this sub-sample, however, is similar to the regional composition of the possible PPA universe shown earlier in Table 1, suggesting that the sub-sample is at least broadly representative of the U.S. as a whole.

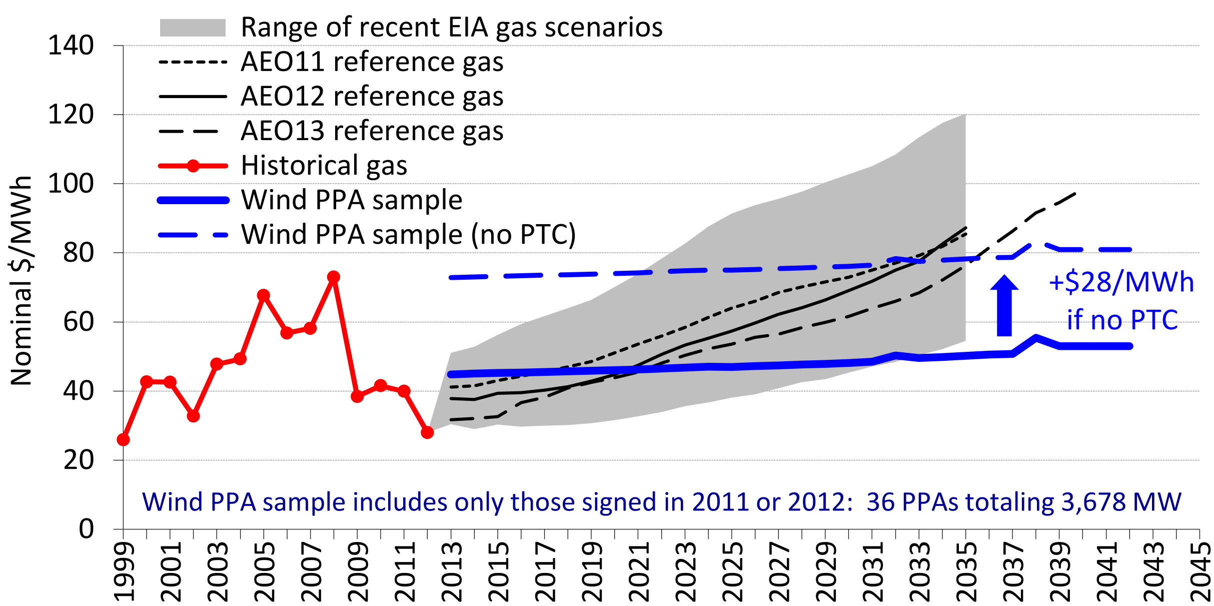


Figure 9. Comparison of Recent Wind PPA Sub-Sample to Projected Range of Natural Gas Prices

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[27] Because of the then-scheduled expiration of the PTC at the end of 2012 and considerable uncertainty over whether or in what form it might be extended, there were very few wind PPAs signed in 2012. Instead, most of the build-out of wind projects in 2012 involved projects that had signed PPAs back in 2011 or earlier. The LBNL sample shown in Figure 9 includes 3,196 MW of wind capacity that signed a PPA in 2011, and another 482 MW that signed a PPA in 2012.

Figure 9 shows that these recent wind PPA prices are quite competitive with natural gas fuel cost projections. The average wind PPA price holds steady in the mid-$40/MWh range, and by 2022 lies below all three reference case gas price projections, eventually falling outside of the cone of uncertainty altogether in 2033. In other words, not only do these recent wind PPAs provide ample long-term hedge value, but they are also, on average, competitive natural gas fuel savers in the near-term when compared to reference-case natural gas price projections for the U.S. as a whole.

As discussed earlier in Section 2.1, however, the wind PPA prices in the LBNL sample reflect the receipt of government incentives, most notably the federal PTC. The PTC is a 10-year, inflation-adjusted income tax credit with a post-tax value that stood at $22/MWh in 2012, which translates into a pre-tax, revenue-equivalent value of $28/MWh (in nominal dollars) levelized over a 20-year period.[28] In other words, without the benefit of the PTC, wind PPA prices could potentially increase by as much as $28/MWh in order to compensate for the loss of the credit in providing the same financial return to investors. As shown by the dashed blue line in Figure 9, shifting the recent wind PPA price curve upwards by this amount results in a significant challenge to wind's near-term competitiveness as a natural gas fuel saver. Even without the benefit of the PTC, however, these contracts still provide some long-term hedge value in later years of the comparison.

In summary, Figures 8 and 9 demonstrate that – even in today's low gas price environment, and with the promise of shale gas having driven down future gas price expectations – wind power can still provide protection against many of the higher-priced natural gas scenarios contemplated by the EIA. This is particularly true among the most recent PPAs in the LBNL sample, which likely better represent current wind PPA pricing, at least on a national average basis. These newer wind contracts not only provide ample long-term hedge value, but on average are also directly competitive as a natural gas fuel saver (at least when compared to reference-case gas price projections) in the near term. Without the benefit of the PTC, wind's near-term competitiveness is challenged, but long-term hedge value still remains.

[28] This conversion involves grossing up the PTC's after-tax value by the marginal income tax rate (to get to a pre-tax revenue-equivalent value) and then levelizing the 10-year pre-tax revenue stream over a 20-year period (since 20 years is the average term of the PPAs in the LBNL sample). The resulting 20-year levelized pre-tax value of $28/MWh likely represents an upper bound to the PTC's value, since it assumes the same cost of capital with and without the PTC. In practice, if the PTC did not exist, wind developers would likely forego expensive tax equity in favor of cheaper debt capital, resulting in a lower overall cost of financing without the PTC, and hence a lower value attributed to the PTC itself.

5. Conclusions

Expanding production of the United States' vast shale gas reserves in recent years has put the country on a path towards greater energy independence, enhanced economic prosperity, and (potentially) reduced emissions of greenhouse gases and other pollutants. The corresponding expansion of gas-fired generation in the power sector – driven primarily by lower natural gas prices – has also made it easier and cheaper to integrate large amounts of variable renewable generation, such as wind power, into the grid. Opportunities abound for even greater cooperation and coordination between cheap natural gas and wind power in the years ahead (Lee et al. 2012).

At the same time, however, low natural gas prices have suppressed wholesale power prices across the nation, making it harder for wind and other renewable power technologies to compete on cost alone – even considering their recent cost and performance improvements. A near-term softening in policy-driven demand from state-level RPS policies (in large measure because wind and other renewables have, in recent years, been added at a pace that exceeds state RPS targets), coupled with a likely phase-out of the federal PTC over time, may exacerbate wind's challenge in the coming years.

If wind power finds it more difficult to compete with gas-fired generation on the basis of near-term cost, it will increasingly need to rely on other attributes, such as its "portfolio" or "hedge" value, as justification for inclusion in the power mix. This article finds that wind's hedge value is as important today as it has ever been – i.e., despite the current low gas price environment, wind power can still provide a useful hedge against rising natural gas prices, particularly over the long term.

At least from a hedging perspective, this long-term hedge value is arguably more important than whether or not wind is competitive as a natural gas fuel saver in the near term. This is because short-term gas price risk can already be effectively hedged using conventional instruments like futures, options, and bilateral physical supply contracts. It's only when one tries to lock in prices over longer terms – e.g., greater than five or ten years – that these conventional hedging instruments come up short. It is over these longer-term durations where inherently stable-priced generation options like wind power hold a rather unique competitive advantage.

Recent statements from two prominent buyers of wind power – the Public Service Company of Colorado ("PSCo") and Google – highlight the importance of long-term hedge value in their purchase decisions. For example, in testifying before regulators about its recent 25-year PPA with the 200 MW Limon II wind project, PSCo noted that "Whenever wind energy is generated from the Limon II facility, it will displace fossil-fueled energy on the Public Service system, mostly energy generated from natural gas. We think of this wind contract as an alternative fuel, with known contract pricing over 25 years that will displace fuels where the pricing is not yet known. That is the essence of the fuel hedge" (Haeger 2012). PSCo also notes the difficulties of replicating this same degree of long-term price stability through the natural gas market: "We typically don't have a lot of long-term natural gas contracts…especially ones that go out 25 years. So this [the Limon II wind contract] is basically providing a long-term fuel contract or energy contract at known prices" (Haeger 2011).

Google, meanwhile, has entered into long-term PPAs with at least two different wind projects, with the primary purpose of hedging the cost of electricity at its data centers. When asked about these wind PPAs, a Google official stated "We see value in getting a long-term embedded hedge. We want to lock in the current electricity price for 20 years. We are making capital investment decisions [regarding data centers] on the order of 15 to 20 years. We would like to lock in our costs over the same period. Electricity is our number one operating expense after head count." He went on to say that Google's interest is primarily long-term in nature: "We are less concerned about hedging our cash flows on a quarter by quarter basis. We are more concerned about the long term." As such, even though the wind PPA prices that Google is paying are apparently above-market in today's low wholesale power price environment, "We just want to ensure the project is there in the later years" – i.e., when wholesale power prices are less certain and therefore price protection is presumably more important (Chadbourne & Parke LLP 2011).

At least for these two prominent and very different purchasers of wind power in the U.S., long-term hedge value appears to be an important consideration. Greater and more widespread recognition of wind's portfolio value among other potential wind power purchasers could help the nation to move forward – even within an era of low natural gas prices, and even if the PTC is eventually phased out – with *both* gas-fired *and* renewable generation.

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