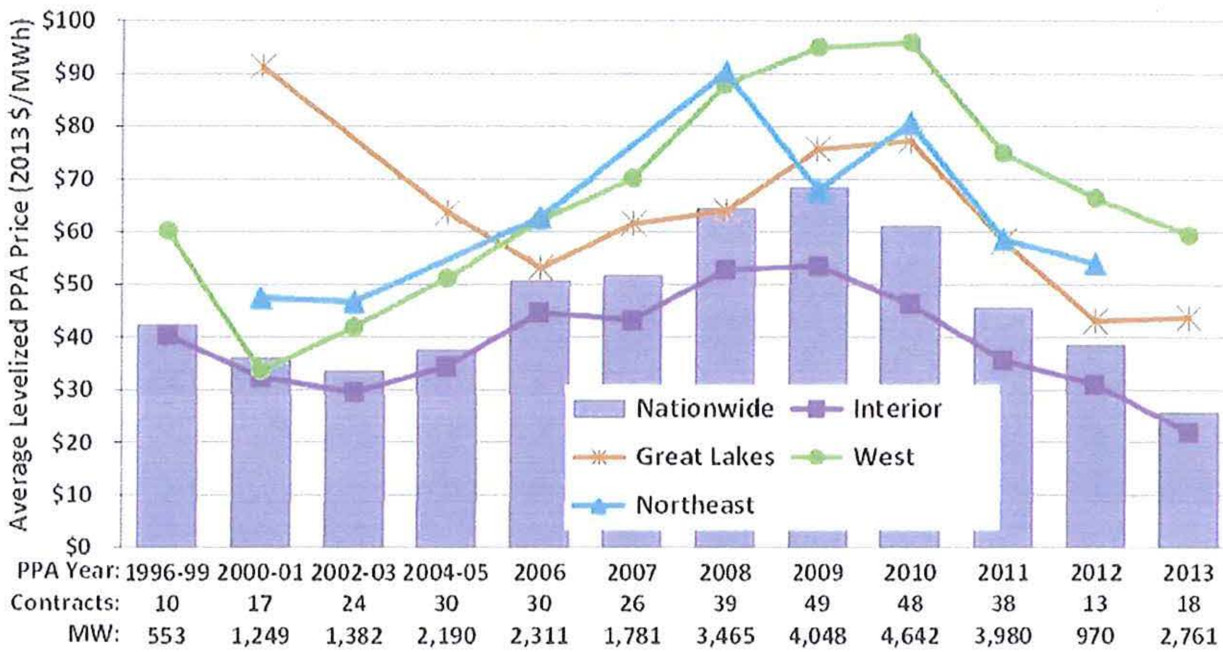
U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

2013 WIND TECHNOLOGIES MARKET REPORT

AUGUST 2014

that the turbine scaling and other improvements to turbine efficiency described in Chapter 4 have more than overcome these headwinds to help drive PPA prices lower.



Source: Berkeley Lab

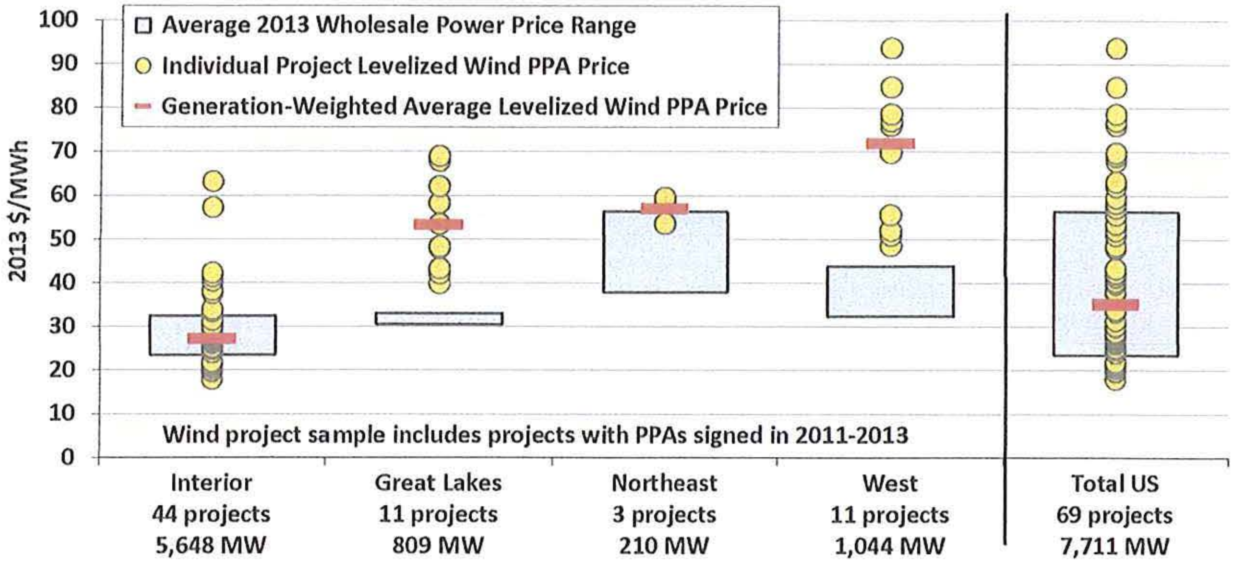
Figure 46. Generation-weighted average levelized wind PPA prices by PPA execution date and region

Figure 46 also shows trends in the generation-weighted average levelized PPA price over time among four of the five regions broken out in Figure 30 (the Southeast region is omitted from Figure 46 owing to its small sample size). Figures 45 and 46 both demonstrate that, based on our data sample, PPA prices are generally low in the U.S. Interior, high in the West, and in the middle in the Great Lakes and Northeast regions. The large Interior region, where much of U.S. wind project development occurs, saw average levelized PPA prices of just $22/MWh in 2013.

The relative competitiveness of wind power improved in 2013

Figure 47 shows the range (minimum and maximum) of average annual wholesale electricity prices for a flat block of power[64] going back to 2003 at 23 different pricing nodes located throughout the country (refer to the Appendix for the names and approximate locations of the 23 pricing nodes represented by the blue-shaded area). The dark diamonds represent the generation-weighted average levelized wind PPA prices in the years in which contracts were executed (consistent with the nationwide averages presented in Figure 46).

[64] A flat block of power is defined as a constant amount of electricity generated and sold over a specified period. Although wind power projects do not provide a flat block of power, as a common point of comparison a flat block is not an unreasonable starting point. In other words, the time variability of wind energy is often such that its wholesale market value is somewhat lower than, but not too dissimilar from, that of a flat block of (non-firm) power (Fripp and Wiser 2006).



Source: Berkeley Lab, Ventyx, IntercontinentalExchange

Figure 48. Levelized long-term wind PPA prices in 2011-2013 and yearly wholesale electricity prices by region

The comparison between levelized wind PPA and wholesale power prices in Figures 47 and 48 is imperfect for a number of reasons (discussed further below), one of which is that the levelized wind PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale power prices are pertinent to just the single year in question. Figure 48 attempts to remedy this temporal mismatch by presenting an alternative and still simple way of looking at how wind stacks up relative to its competition.

Rather than levelizing the wind PPA prices, Figure 49 plots the future stream of average wind PPA prices from PPAs executed in 2011, 2012, or 2013 against a range of projections of just the fuel costs of natural gas-fired generation.[65] As shown, average wind PPA prices from contracts executed in 2011 and 2012 start out higher than the range of fuel cost projections, but decline (in real 2013$) over time and soon fall within and then eventually below the range. The sample of PPAs executed in 2013 has an average price stream that *begins* below the range of natural gas fuel cost projections, and that remains below even the low-end of gas price forecasts for two decades.

[65] The fuel cost projections come from the Energy Information Administration's *Annual Energy Outlook 2014* publication, and increase from around \$4.60/MMBtu in 2013 to \$8.65/MMBtu (in 2013 dollars) in 2040 in the reference case. The range around the reference case is bounded by the high and low oil and gas resource cases, and ranges from \$5.50/MMBtu to \$11.50/MMBtu (again, in 2013 dollars) in 2040. These fuel prices are converted from \$/MMBtu into \$/MWh using the heat rates implied by the modeling output (these start at roughly 8,300 Btu/kWh and gradually decline to around 7,100 Btu/kWh by 2040).

regulations released in late 2013 that would restrict carbon emissions from new power plants as well as proposed regulations released in June 2014 that would apply carbon restrictions to existing power plants. Finally, R&D investments by the U.S. DOE continue, and hold the prospect of helping to further reduce the cost of wind energy in the future.

State policies help direct the location and amount of wind power development, but current policies cannot support continued growth at recent levels

From 1999 through 2013, 69% of the wind power capacity built in the United States was located in states with RPS policies; in 2013, this proportion was 93%.[66] As of June 2014, mandatory RPS programs existed in 29 states and Washington D.C. (Figure 50).[67] Although no new state RPS policies were passed in 2013, some states strengthened previously established RPS programs. Attempts to weaken RPS policies also have been initiated in a number of states, and in limited cases—including in Ohio, in 2014—have led to meaningful changes in RPS design.

In aggregate, existing state RPS policies require that by 2025 (at which point most state RPS requirements will have reached their maximum percentage targets) at least 9% of total U.S. generation supply will be met with *RPS-eligible* forms of renewable electricity, equivalent to roughly 106 GW of renewable generation capacity.[68] Incremental growth in RPS requirements through 2025 represents 40% of projected growth in total U.S. electricity generation over that timeframe, although some portion of the growth in RPS requirements may be met with existing capacity (e.g., in regions that are currently over-supplied relative to their RPS targets).

Given the size of RPS targets and the amount of new renewable energy capacity that has been built since enactment of those policies, Berkeley Lab projects that existing state RPS programs require average annual renewable energy additions of roughly 3–4 GW/year through 2025, not all of which will be wind.[69] This is below the average of 7 GW of wind power capacity added in each year over the 2007–2013 period, and even further below the 9 GW per year of total renewable generation capacity added during that time frame, demonstrating the limitations of relying exclusively on state RPS demand to drive future wind power development.

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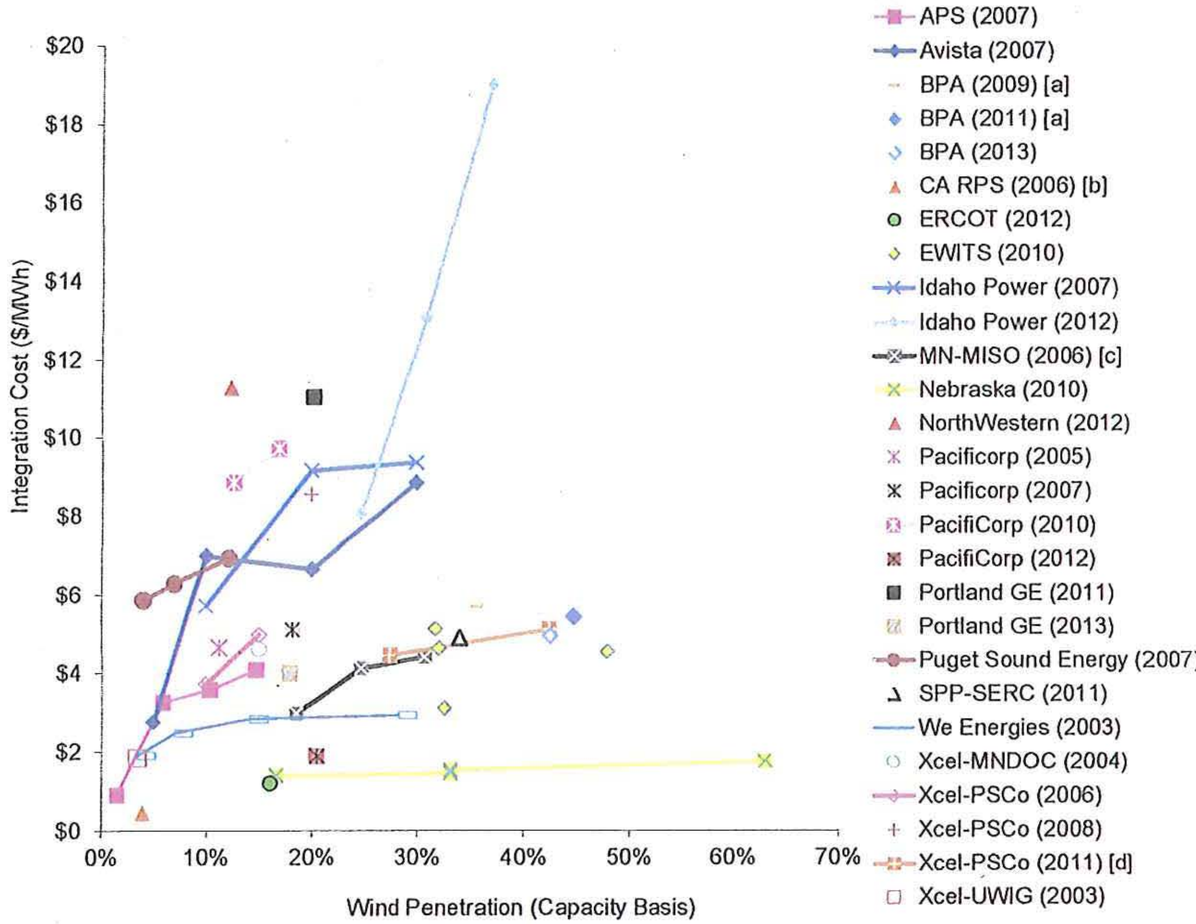
[66] Such statistics provide only a rough indication of the impact of RPS policies on wind power development and could either overstate or understate the actual policy effect to date.
[67] Mandatory RPS policies and non-binding renewable energy goals also exist in a number of U.S. territories, but are not shown in Figure 50.
[68] Berkeley Lab's projections of new renewable capacity required to meet each state's RPS requirements assume different combinations of renewable resource types for each RPS state, although they do not assume any biomass co-firing at existing thermal plants. To the extent that RPS requirements are met with a larger proportion of high-capacity-factor resources than assumed in this analysis or with biomass co-firing at existing thermal plants, the required new renewable capacity would be lower than the projected amount presented here.
[69] Again, varying combinations of renewable resource types for each RPS state were assumed in estimating the 3–4 GW/year of average annual renewable capacity additions required to meet RPS obligations through 2025. As a point of comparison, AWEA (2013) forecasts roughly 2.4 GW/year of wind additions from 2013 through 2025 as a result of state RPS requirements.

Two new integration costs studies were completed in 2013, both by organizations that had previously completed studies already included in this review: Portland General Electric (PGE) and BPA. In both cases, the new wind integration cost estimate was lower than in the previous study by the same entity. In the case of PGE, the substantial reduction (from over $11/MWh to less than $4/MWh) was attributed to the addition of flexible balancing resources and increased wind diversity (PGE 2014).



[a] Costs in $/MWh assume 31% capacity factor.
[b] Costs represent 3-year average.
[c] Highest over 3-year evaluation period.
[d] Cost includes the coal cycling costs found in Xcel Energy (2011).

Figure 52. Integration costs at various levels of wind power capacity penetration[71]

In addition to wind integration costs, a number of studies examine the impact of changes to existing practices in power system operations, the role of forecasting, and the capability of supply- and demand-side technologies in providing the needed flexibility to integrate wind power. Conclusions from recent integration studies include the following:

[71] References for studies conducted prior to 2013 can be found in previous versions of the Wind Technology Market Report. Sources for new studies include: BPA (2013) and PGE (2014).