Renewable Energy and Wholesale Electricity Price Variability

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See footnotes at end of text.

It is well understood that wholesale price variability is a fundamental feature of deregulated electricity markets. Around the world, nearly all advanced economies have made the move toward deregulation, and have correspondingly seen an increase in the variability of wholesale electricity prices. This variation stems from an array of factors, including (but not limited to) fuel price shocks, availability of generation capacity, unexpected outages, demand inelasticity, exogenous demand variations, and transmission constraints (Benini et al., 2002).

At the same time, non-hydro renewable energy (RES-E) – led by technologies such as wind, solar, tidal, and geothermal power – continues to penetrate the market for generation in a significant way. According to International Energy Agency (IEA) statistics, these sources accounted for 0.37 percent of OECD total electricity supply in 1990, compared to 5.36 percent in 2013 (see Table 1). In absolute terms the increase has been equally remarkable. Meanwhile, the share of total generation from conventional fossil fuels (specifically oil and coal) has declined precipitously.[1] Moreover, the increase in the share of RES-E technologies in total generation varies widely across countries, in large part due to varying levels of political and economic support for RES-E investment. In the United States, RES-E accounted for 0.61 percent of total generation in 1990, compared to 4.66 percent in 2013. In Germany, these technologies produced barely 0.01 percent of total supply in 1990, but by 2013 had increased their share considerably to approximately 13.13 percent. Given continuously increasing public concern about the potentially disastrous climate effects of carbon emissions, many scholars would argue the transition toward RES-E generation is only just beginning to take off at a global level.

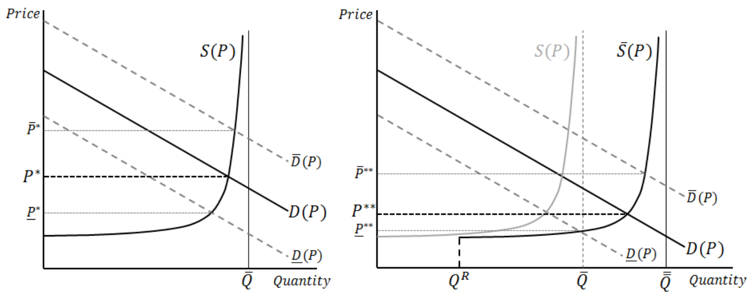
Source	1990	2000	2013
Wind	3,844	28,534	435,854
Solar PV/ thermal	681	1,244	111,136
Geothermal	23,190	25,752	33,973
Tidal/ocean	529	539	959
Total non-hydro RES-E	28,244	56,069	581,922
Pct. of total generation	0.37	0.57	5.36

Table 1. RES-E generation: 1990 versus 2013, OECD total (GWh).
Source: IEA (2014a,b).

Traditionally, economists and policy-makers have cited revenue risk from price variation (in conjunction with the high levelized cost per kWh of RES-E compared to conventional fuels) as the primary inhibitor of investment in RES-E generation. Indeed, shielding investors from risk has been a key feature of most RES-E support policies—feed-in tariffs or renewable portfolio standards, for example (Schmalensee, 2012). However, we argue that as RES-E continues to penetrate countries' total generation portfolios, the short-run variation in wholesale electricity prices is likely to decline.

The key to understanding this effect is that these technologies enter at the base of the generation mix, and not at the margin. To see why, consider Joskow's (2011) clear distinction between dispatchable and intermittent electricity generation technologies. He defines dispatchable technologies as those that "can be controlled by the system operator and can be turned on and off based primarily on their economic attractiveness at every point in time,"—e.g., coal, natural gas, or nuclear. By contrast, intermittent technologies like wind and solar depend on exogenous weather characteristics, and thus typically cannot be dispatched by the system operator to balance supply and demand at any given point in time. In other words, intermittent generation cannot be used as a marginal supply source. Additionally, because most RES-E technologies have a marginal cost of generation near zero, when these generators are able to operate, they enter at the base of the total electricity supply curve. Given the amount of RES-E generation, system operators then balance residual demand with supply by dispatching conventional power sources at the margin.

To see the underlying microeconomic intuition for why increased RES-E generation should be expected to reduce short-run wholesale price variation, consider the simple graphical model of an electricity market presented in Figure 1. Panel (a) depicts the market with zero RES-E generation. The short-run supply curve for conventional generation is $S(P)$ where P is the wholesale electricity price. Define maximum capacity as Q. Consistent with conventional wisdom, we assume the electricity supply curve remains relatively flat over most of its range, but rises sharply as output approaches the capacity constraint. The expected demand curve for electric power is $D(P)$, which stochastically shifts up and down in the short run as a result of random, exogenous demand shocks.[2] The expected equilibrium price is



(a) Withoug RES-E (b) With RES-E

Figure 1. Simple Model of an Electricity Market.

P^*. For simplicity, let the upper bound for a positive demand shock be $\overline{D}(P)$ and the lower bound for a negative shock be $\underline{D}(P)$. The equilibrium price thus varies stochastically in the short run between its upper and lower bounds of $\overline{P}^*$ and $\underline{P}^*$.

Panel (b) depicts the market with RES-E output of Q^R. Because Q^R enters at the base of the generation mix, this shifts the short-run conventional electricity supply curve to the right by Q^R units to $S(P)$, and maximum output for the market is now $Q = \overline{Q} + Q^R$. Given the same expected demand curve and range of variation from demand shocks, the equilibrium price fluctuates between $\overline{P}^*$ and $\underline{P}^{**}$, which is clearly a tighter range of short-run variation than was the case without RES-E. In addition, the expected equilibrium price, P^{**}, is lower.[3] Note that the same intuition applies even when Q^R is stochastic.

The economic implications of this effect are straightforward. Reduced variability in wholesale electricity prices would reduce revenue risk for RES-E investors, which may alleviate (at least in part) the need for transfers associated with RES-E support schemes. Lower price risk is likely to provide additional benefits as well—first, to utility service providers, by way of reduced resources devoted to costly risk management strategies; and second, through lower risk premiums passed on to electricity consumers.

To our knowledge, these effects have yet to be fully explored in the literature. We are currently engaged in a cross-country empirical analysis using wholesale electricity price and generation data; early results support the theory that greater RES-E penetration reduces the variation in wholesale electricity prices. Ultimately, we seek to quantify the effect for different RES-E support schemes, which will aid policy makers seeking to implement such schemes in order to increase the share of RES-E in total generation and meet CO_2 emission reduction goals.

Footnotes

[1] Much of this decline has been offset by an increase in generation from natural gas, biofuels, and renewable waste.

[2] Demand also follows predictable hourly and seasonal patterns.

[3] Sáenz de Meira et al. (2008) have found empirical support for this prediction. In the case of wind generation in Spain, the increase in electricity production from wind power led to a reduction in wholesale electricity prices.

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