Energy Policy 60 (2013) 122–131

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Determining the impact of wind on system costs via the temporal patterns of load and wind generation

Clay D. Davis [a,*], Douglas J. Gotham [b], Paul V. Preckel [c], Andrew L. Liu [d]

[a] 11 Wayland St. Unit 2, Delmar, NY 12054, USA
[b] Indiana State Utility Forecasting Group, Discovery Park, Purdue University, Mann Hall, 203 South Martin Jischke Drive, West Lafayette, IN 47907-1971, USA
[c] Department of Agricultural Economics, Purdue University, 403 West State Street, West Lafayette, IN 47907-1145, USA
[d] School of Industrial Engineering, Purdue University, 315 N. Grant Street, West Lafayette, IN 47907-1971, USA

HIGHLIGHTS

- We estimate the value of wind capacity.
- We determine wind generation's impact on the optimal mix of non-wind generation.
- Optimal levels of wind and non-wind generation are determined.
- We consider the impact of a carbon price on the optimal mix of resources.
- The impact of additional wind capacity on Indiana residential rates is calculated.

ARTICLE INFO

Article history:
Received 7 April 2013
Accepted 27 April 2013
Available online 24 May 2013

Keywords:
Wind power
Capacity value
Intermittent generation

ABSTRACT

Ambitious targets have been set for expanding electricity generation from renewable sources, including wind. Expanding wind power impacts needs for other electricity generating resources. As states plan for increasing levels of wind generation in their portfolio of generation resources it is important to consider how this intermittent resource impacts the need for other generation resources. A case study for Indiana estimates the value of wind capacity and demonstrates how to optimize its level and the levels of other generation resources. Changes are driven by temporal patterns of wind power output and load. System wide impacts are calculated for energy, capacity, and costs under multiple wind expansion scenarios which highlight the geographic characteristics of a systems portfolio of wind generation. The impacts of carbon prices, as proposed in the Bingaman Bill, are considered. Finally, calculations showing the effect increasing levels of wind generation will have on end use Indiana retail rates are included.

1. Introduction

Increases in wind generation's share of states' generation portfolios, increase the need to understand how wind generation impacts needs for other generating resources. Due to its intermittency, increasing the level of energy generated from wind will alter the operational and capacity requirements of other generation resource types (e.g. baseload, cycling and peaking).

Wind generation is not dispatchable—that is, generation output cannot be increased at will to meet increases in electricity demand. Because it has zero fuel cost, wind generation is usually considered a price taker; so it is the combination of wind power variability in addition to load variability that the remaining generating units in the system must be able to meet (Wan, 2011). The temporal patterns of wind generation and electricity demand define the net load that must be served by other generation resources to meet demand at any given time (Wan, 2011). While wind generation may reduce the overall amount of energy needed from the other generation resources, it may also shift the needs among generation resource types. A load net of wind duration curve may be used to determine the optimal mix of non-wind generation resources and is created by sorting per period load minus per period wind generation in descending order. Doherty et al. (2006) show increases in penetration of wind generation cause a steepening of the load net of wind duration curve and result in increases in peaking capacity needs and reductions in baseload needs.

Most of the existing work on valuing wind capacity has focused on reliability for serving peak load (see e.g. Milligan and Porter,

* Corresponding author. Tel.: +1 785 317 0350.
E-mail addresses: cdd5555@gmail.com (C.D. Davis), gotham@purdue.edu (D. J. Gotham), preckel@purdue.edu (P.V. Preckel), andrewliu@purdue.edu (A.L. Liu).

0301-4215/$ - see front matter © 2013 Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.enpol.2013.04.063

2008; Billinton and Bai, 2004). While this is an important dimension of the problem, it does not directly address the impact of investments in wind capacity on electricity prices. While there has been a fair amount of work on the cost of wind capacity (e.g Junginger et al., 2005; Dale et al., 2004), work on the value of capacity – i.e. the impact of wind on the average cost of serving load – in the context of an existing generating system is more limited. Karki and Billinton (2004) use simulation modeling to estimate the cost savings due to varying levels of installed wind capacity finding that the offset fuel cost increases at a decreasing rate as wind turbines are added and that wind utilization efficiency declines as turbines are added.

Puga (2010) shows that large amounts of wind capacity will require increased levels of capacity with fast-ramping capabilities. He also shows that high levels of wind capacity can lead to increased cycling of baseload units, particularly during periods of low load and high wind. Increased cycling of baseload generation may lead to higher O&M costs and have implications for unit lifetimes.

Delarue et al. (2011) use a portfolio theory approach to determine the optimal mix of generation resources by using a linear program to minimize the cost of meeting demand subject to ramping limits on generation, but does not allow for the possibility of wind curtailment. In this framework it may be beneficial to curtail wind generation if ramping of the load net of wind generation exceeds ramping capabilities of non-wind resources. Curtailing wind may result in lower system costs if it reduces the need to build more expensive, faster ramping units that will be used to meet infrequent large ramp events.

While these papers cover various aspects of wind generation, they do not consider both operational and planning aspects simultaneously and ultimately the impact this will have on retail electricity prices. Increasing levels of wind generation will not only impact operational decisions (economic dispatch), but also the optimal mix of generation resources determined during the resource planning period. Doherty et al. (2006) determine capacity needs of non-wind generation resources as wind capacity is increased using a minimum cost economic dispatch framework, but their paper focuses on Ireland where characteristics of wind generation and the existing resource mix may be very different than the wind generation and resource mix in Indiana. The model developed in Section 2 reflects not only investment costs of wind capacity expansion and fuel savings, but also the impact on investment in other generation capacity. Capacity resource levels are determined relative to existing levels, so the optimal resource mix is not independent of the existing Indiana capacity levels. Section 3 considers various wind capacity expansion scenarios to determine the benefits from geographic diversification and Section 4 covers the rate impact on retail customers in the state of Indiana as a result of increased levels of wind generation. This impact on retail rates is of value to policymakers as this paper shows how changes in system costs due to larger levels of wind generation will directly impact end use retail customers.

2. Methodology

This paper provides a framework for assessing the impact of wind generation on the need for other generation resources, using the state of Indiana as an example. Here, we use observed load data for 2004–2006 for the state of Indiana and estimated wind generation data from the National Renewable Energy Laboratory (NREL, 2010) to estimate the impact of wind generation on system costs and on the need for other generation types. Since Indiana is a regulated state it is important for capacity planning purposes to consider the effect of additional wind generation committed to serving Indiana load on other resources within the state. Baseload, cycling and peaking generation assets are represented by different technologies (pulverized coal for baseload and existing cycling capacity, natural gas combined cycle for new cycling capacity and natural gas combustion turbine for both existing and new peaking capacity). Installed generation assets are based on existing 2007 Indiana capacity, and capacity additions to meet projected demand in 2025 are determined for alternative levels of wind generation capacity assuming a 10% reserve margin. A reserve margin of 10% is included to account for unit outages. Using a reserve margin of 10% is an approximate method to limit the loss of load probability and is applied across all scenarios for comparability. Thus, our results reflect not only the investment costs of the wind capacity expansion and fuel savings, but also the impact on investment in other generation capacity.

The impacts of increased wind generation capacity on Indiana utilities' generation portfolios are calculated in four areas: changes in generating capacity needs for baseload, cycling, and peaking capacity; the change in energy (MWhs) supplied by baseload, cycling, and peaking generating units; changes in capital costs due to changes in capacity requirements; and changes in variable costs resulting from changes in energy requirements.

Hourly load data for the state of Indiana for 2004–2006 is used for the analysis (SUFG, 2009b). Wind generation data were acquired from the National Renewable Energy Lab's Eastern Wind Integration and Transmission Study (NREL, 2010). This study developed wind generation estimates at 10-min intervals for various sites throughout the eastern United States. The time period of the wind estimates coincides with the Indiana load data, which is important because wind speed affects both data types. (E.g. during the summer months higher wind speeds will lead to increased wind generation and reductions in air conditioning load.)

For this analysis, wind sites were chosen in close proximity to 2009 Indiana wind power purchase agreement (PPA) sites (SUFG, 2009a). The site capacities were initially scaled to the wind capacity agreed upon in the 2009 Indiana power purchase agreements, totaling 770 MW. The load data for each year were scaled from the respective year up to the forecasted load in 2025 (SUFG, 2009b). That is, each annual load profile was scaled such that annual energy consumption is equivalent to the projected consumption in 2025 (144,495 GWh). The three years of load data were all scaled to the same year (2025) in order to generate three distinct annual load profiles. Impacts were calculated for each of the three years and averaged. The hourly load data were linearly interpolated to 10 min intervals, so as to correspond to the frequency of the wind generation data.

2.1. Capacity impact calculations

Capacity requirements were calculated for the three generation resource types (baseload, cycling, and peaking) as wind capacity was added relative to a base resource case, which includes existing 2007 capacities plus planned capacity changes. The base resource case capacity levels are: 16,426 MW baseload, 2500 MW cycling, and 3585 MW peaking.

Load net of wind duration curves (LDCs) were created using the load net of wind profiles at each level of wind generation capacity (see Fig. 1). A load net of wind duration curve sorts the 10 min load minus the 10 min wind generation for each interval of the year from the highest to the lowest. The greater the difference between the highest and lowest load net of wind period of the year the more load net of wind varies throughout the year. In this analysis, there is no wind generation uncertainty, so that the analysis effectively assumes a perfect wind forecast. Since wind generation has near zero variable costs and wind power purchase agreement contracts are “take-or-pay” (i.e. the utility must pay for the wind