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CrossMark

The Controllability of Real Things: Planning for Wind Integration

The authors employed a novel optimization framework coupled with an econometric model of wind to study market performance. One conclusion: in circumstances with high uncertainty in the market – as with high penetration of renewables – relying more on a real-time market, similar to the National Electricity Market in Australia, may be a better way to deal with this uncertainty because it uses updated and more accurate information about the wind variability.

Wooyoung Jeon, Alberto J. Lamadrid, Jung Youn Mo and Timothy D. Mount

Don't gamble; take all your savings and buy some good stock and hold it till it goes up, then sell it. If it don't go up, don't buy it.

– Will Rogers

I. Introduction and Motivation

In 1897, the Askov Folk High School in Denmark had a couple of test wind turbines, six years after building the first wind turbine in part funded by the Danish government. Over a century later, the path to adoption of renewable energy sources (RES) is underway in many U.S. states and in other countries. A major obstacle faced in this transition to a low-carbon economy has been the technical and regulatory hurdles faced when adopting resources that are

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intermittent in nature. While many in the industry and regulatory bodies at the state and federal level are stubbornly set in managing these RES as traditional, controllable resources, the reality is that the physical characteristics of the renewable resources affect the benefits that can be derived from their use, and the models used may introduce biases in their management and compensation.

The objective of this article is to evaluate how the management of the conventional units in the system is affected by the way that the RES uncertainty is modeled, for the specific case of wind energy. In particular, we are interested in three global metrics: (1) the inter-temporal changes in generation, specifically, the ramping up and down from any given dispatch point, that conventional generators perform; (2) the dispatch of all generators, including wind and their associated costs; and (3) the reliability of the system, as measured by the possibility of not serving load.

The importance of our chosen metrics is that, first, they follow the real economic performance associated with the operation of the system. We use hourly steps as the observation time scale, to maintain consistency in the way the system operates. Namely, the dispatch orders in this time scale follow instructions from system operators (SOs), whose objective is to maximize social welfare. Therefore, the commands that conventional generators receive are presumably oriented toward improving the overall operation of the system.[1] Second, conventional generators are incurring a series of costs, including ramping, that in some cases are not compensated. For example, while in most markets there is a clear mechanism to remunerate fuel costs and the cost of reserves (Gan and Litvinov, 2003), the ramping costs are still not clearly defined or understood. Consequently, the evaluation of the system performance, should include the economic costs incurred, or in other words, internalize the externality. And third, SOs must assure the reliability of the system, aiming to minimize the number of service interruptions (e.g., one day in 10 years). This is basically equivalent to a probability for the social planner (the SO), that constraints the dispatch schedules provided to generators, and most notably, may lead them to decide to use less RES than the expected available capacity, if the cost of accommodating it exceeds its benefits.

Many in the industry and regulatory bodies at the state and federal level are stubbornly set in managing these RES as traditional, controllable resources.

Our analysis combines a statistical model with a simulation of the optimization performed by the system operator. Due to the wide variability of criteria used by system operators (Ela et al., 2011), the optimization model we apply has what we consider a set of desirable characteristics: (1) the economic valuation of producer surplus and consumer surplus, including compensation in cases in which demand is not fulfilled; (2) the determination of different types of ancillary services from the information provided on the operation of the system (i.e., endogenously determined); (3) the regulatory constraints for the reliable operation of the system (e.g., operating reliability, resource adequacy – NERC (2013)); (4) the explicit constraints of the physical system (e.g., Kirchhoff's laws, generation capabilities), and (5) the possibility to dispatch less than the total RES available power capacity (e.g., spilling wind power).

The econometric model is a time series fit of hourly data reproducing the wind speed and load across the northeastern states of the U.S., for a specified day. The simulations are conditional on the temperature forecast of the selected day, and they capture the spatial correlations between the wind speed and the load across the different sites.

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