Peak-load pricing with different types of dispatchability

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(1) Overview

We investigate the peak load pricing problem if technologies differ in their dispatchability, and show that some standard results on peak load pricing under uncertainty are reversed. Our theoretical model introduces three types of dispatchability: highly dispatchable generators that qualify for a short-term reserve (like gas turbines), medium dispatchable generators (as nuclear, coal and large-scale biomass) and non-dispatchable generators (fluctuating, as wind and PV). The consequences of different degrees of dispatchablity has, to our knowledge, not yet been considered in the theory of peak load pricing under uncertainty (cf. Chao 1983; Kleindorffer & Fernando 1993; Crew et al. 1995, Chao 2011).

An increasing share of fluctuating renewable electricity feed-in can cause additional electricity system costs (Lamont 2008; 'cost of variability', Hirth 2013). This basically stems from the non-dispatchability of fluctuating renewable electricity generators. The argument roughly runs as follows. First, non-dispatchable generators operate at very low marginal costs. This places them at the base-load part of the merit order (being reflected by priority dispatch in some renewable subsidy schemes). Thus, non-dispatchable generators substitute conventional base-load generators. However, if actual feed-in is lower than expected due to fluctuations, reserve capacities need to be used. Such reserve capacities come at higher costs than the conventional generators that are crowded out by renewables.

There is yet one additional underlying reason for the increasing system costs involved here: The more expensive reserve capacities would not be needed if the cheaper conventional base-load power plants would be highly dispatchable as well. However, typical base-load generators need several hours to be shut down or restart. Producion decisions need to deal with the unit commitment problem and are usually made one day ahead. This is one explanation for eventual requests by utilities to temporarily shut-down renewable generators, or for negative electricity market prices in times of very high renewable feed-in.

(2) Methods

We develop a stylized peak-load model that assumes supply side uncertainty for non-dispatchable generators. These are assumed to be competitive, so subsidy or quota schemes for promotion of renewables are absent. We then determine how dispatchability influences the optimal capacity decision, whether renewables will indeed crowd out conventional generators and require more reserve capacities, and how this is related to optimal prices.

Different types of dispatchability are reflected by a sequential dispatch decision model. In stage 1, long-term capacity decisions for the three types of generators are made by considering capacity costs and the expected profits resulting from the later dispatch decisions. In stage 2, production decisions for mediumdispatchables have to be made. In stage 3, stochastic production of non-dispatchables realizes, and highly-dispatchables can instantaneously adjust to fluctuations. The model determines the socially optimal capacity decisions and prices. Results can also be assessed in terms of cost recovery (is there a missing money problem? Joskow 2008), and compared to the standard results on peak load pricing under uncertainty.

(3) Results

We find qualitatively different cases for the optimal capacity decision that depend, i.a., on the relative costs of the technologies. For the more likely cases, we obtain different results than the established peak-load pricing theory suggests.

Under the standard theory, the lowest marginal cost technology (weighted by the availability factor) is used first (if it is competitive). Thus, competitive renewables would enter the base load, substituting part of conventional base-load plants and requiring additional peak load capacities.

In our analysis, however, medium-dispatchable power plants stay in the base-load (yet with a lower market share), while non-dispatchables are used to serve peak demand, complemented by highly-dispatchables if necessary. More implications of our basic analysis are investigated. We identify conditions for a missing money problem (not) to occur. The paper further explores the consequences for electricity market design, as the analysis suggests product differentiation (along the dimension of dispatchability) as a way to decrease costs.

(4) Conclusions

Our analysis shows that considering generators' different degrees of dispatchability changes the analysis of optimal capacity decisions in a future electricity system with integrated, non-subsidized renewables. This provides are more differentiated picture on when an increasing share of fluctuating renewables needs to be complemented by more reserve capacities.

Literature

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