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Decision Support

Pricing of fluctuations in electricity markets

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ABSTRACT

In an electric power system, demand fluctuations may result in significant ancillary cost to suppliers. Furthermore, in the near future, deep penetration of volatile renewable electricity generation is expected to exacerbate the variability of demand on conventional thermal generating units. We address this issue by explicitly modeling the ancillary cost associated with demand variability. We argue that a time-varying price equal to the suppliers' instantaneous marginal cost may not achieve social optimality, and that consumer demand fluctuations should be properly priced. We propose a dynamic pricing mechanism that explicitly encourages consumers to adapt their consumption so as to offset the variability of demand on conventional units. Through a dynamic game-theoretic formulation, we show that (under suitable convexity assumptions) the proposed pricing mechanism achieves social optimality asymptotically, as the number of consumers increases to infinity. Numerical results demonstrate that compared with marginal cost pricing, the proposed mechanism creates a stronger incentive for consumers to shift their peak load, and therefore has the potential to reduce the need for long-term investment in peaking plants.

1. Introduction

Our motivation stems from the fact that fluctuations in the demand on conventional thermal generating units typically result in significantly increased, and nontrivial, ancillary costs. Today, such demand fluctuations are mainly due to time-dependent consumer preferences. In addition, in the future, a certain percentage of electricity production is required by law in many states in the U.S. to come from renewable sources (Barbose, Wiser, Phadke, & Goldman, March 2008). The high volatility of renewable energy sources may aggravate the variability of the demand for conventional thermal generators and result in significant ancillary cost. More concretely, either a demand surge or a decrease in renewable generation may result in (i) higher energy costs due to the deployment of peaking plants with higher ramping rates but higher marginal cost, such as oil/gas combustion turbines, and (ii) the cost associated with resource redispatch[2] that the system will incur to meet reserve constraints if the demand increase (or renewable generation decrease) causes a reserve shortage.

There is general agreement that charging real-time prices (that reflect current operating conditions) to electricity consumers has the potential of reducing supplier ancillary cost, improving system efficiency, and lowering volatility in wholesale prices (Chao, 2010; Spees & Lave, 2008; US Department of Energy, 2006). Therefore, dynamic pricing, especially real-time marginal cost pricing, is often identified as a priority for the implementation of wholesale electricity markets with responsive demand (Hogan, 2010), which in turn raises many new questions. For example, should prices for a given time interval be calculated ex ante or ex post? Does real-time pricing introduce the potential for new types of market instabilities? How is supplier competition affected? In this paper, we abstract away from almost all of these questions and focus on the specific issue of whether prices should also explicitly encourage consumers to adapt their demand so as to reduce supplier ancillary cost.

To illustrate the issue that we focus on, we note that a basic model of electricity markets assumes that the cost of satisfying a given level A_t of aggregate demand during period t is of the form $C(A_t)$. It then follows that in a well-functioning wholesale market, the observed price should more or less reflect the marginal cost $C'(A_t)$. In particular, prices should be more or less determined by the aggregate demand level. Empirical data do not quite support this view. Fig. 1 plots the real-time system load and the hourly prices on February 11, 2011 and on February 16, 2011, as reported by the New England ISO

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[2] A certain level of reserve must always be maintained in an electric power system. Local reserve shortages are usually due to the quick increase of system load rather than a capacity deficiency. If the increase of system load makes the system short in reserves, the system redispatches resources to increase the amount of reserves available. Redispatch generally increases the generation cost and results in higher prices. The redispatch cost can be very high (cf. Section 2.3.2 of ISO New England Inc., 2010).

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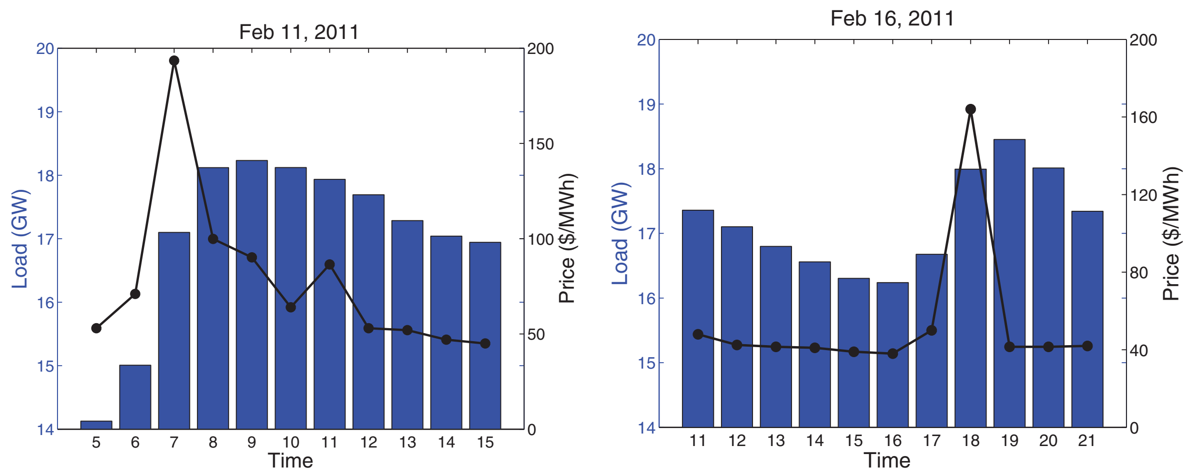

Fig. 1. Real-time prices and actual system load, ISO New England Inc. Blue bars represent the real-time system loads and the dots connected by a black line represent the hourly prices.

(ISO New England Inc., 2011). We observe that prices do not seem to be determined solely by A_t but that the changes in demand, $A_t - A_{t-1}$, also play a major role. In particular, the largest prices seem to occur after a demand surge, and not necessarily at the hour when the load is highest. We take this as evidence that the total cost over $T+1$ periods is not of the form

$$\sum_{t=0}^{T} C(A_t),$$

but rather of the form

$$\sum_{t=0}^{T} \left(C(A_t) + H(A_{t-1}, A_t)\right), \tag{1}$$

for a suitable function H.

We take the form of Eq. (1) as our starting point and raise the question of the appropriate prices. We note that wholesale electricity prices set by an OPF (optimal power flow)-based approach is simply the highest marginal cost of active generating units (Sioshansi, Oren, & O'Neill, 2010; Wu, Rothleder, Alaywan, & Papalexopoulos, 2004): at time t, A_{t-1} has already been realized, and taking its value for granted, a consumer is charged a unit price equal to

$$C'(A_t) + \frac{\partial}{\partial A_t} H(A_{t-1}, A_t), \tag{2}$$

which is the supplier's marginal cost at stage t. We refer to this simple approach as "marginal cost pricing" (MCP), which is essentially the one used in the price calculation processes implemented by the California ISO (2009), New England ISO (Litvinov, 2011), and NYISO (cf. Section 17.1 of NYISO, 2012). However, a simple argument based on standard mathematical programming optimality conditions shows that for system optimality to obtain, the demand A_{t-1} should also incur (after A_t is realized) a unit price of (Sioshansi et al., 2010):

$$\frac{\partial}{\partial A_{t-1}} H(A_{t-1}, A_t), \tag{3}$$

This is in essence the pricing mechanism that we analyze in this paper.[3]

The actual model that we consider will be richer from the one discussed above in a number of respects. It includes an exogenous source of uncertainty (e.g., representing weather conditions) that has an impact on consumer utility and supplier cost, and therefore can incorporate the effects of volatile renewable electricity production[4]. It allows for consumers with internal state variables (e.g., a consumer's demand may be affected by how much electricity she has already used). It also allows for multiple consumer types (i.e., with different utility functions and different internal state dynamics). Consumers are generally modeled as price-takers, as would be the case in a model involving an infinity (a continuum) of consumers. However, we also consider the case of finite consumer populations and explore certain equilibrium concepts that are well-suited to the case of finite but large consumer populations. On the other hand, we ignore most of the distinctions between ex post and ex ante prices. Instead, we assume that at each time step, the electricity market clears. The details of how this could happen are important, but are generic to all electricity markets, hence not specific to our models, and somewhat orthogonal to the subject of this paper. (See however Appendix A for some discussion of implementation issues.)

The ancillary cost function $H(A_{t-1}, A_t)$ is a central element of our model. How can we be sure that this is the right form? In general, redispatch and reserve dynamics are complicated and one should not expect such a function to capture all of the complexity of the true system costs; perhaps, a more complex functional form such as $H(A_{t-2}, A_{t-1}, A_t)$ would be more appropriate. We believe that the form we have chosen is a good enough approximation, at least under certain conditions. To argue this point, we present in Appendix B an example that involves a more detailed system model (in which the true cost is a complicated function of the entire history of demands) and show that a function of the form $H(A_{t-1}, A_t)$ can capture most of the cost of ancillary services.

1.1. Summary and contributions

Before continuing, we provide here a roadmap of the paper together with a summary of our main contributions.

(a) We provide a stylized (yet quite rich) model of an electricity market, which incorporates the cost of ancillary services (cf. Section 2).
(b) We provide some justification of the form of the cost function in our model, as a reasonable approximation of more detailed physical models (cf. Appendix B).

[3] In current two-settlement systems, the real-time prices are charged only on the difference of the actual demand and the estimated demand at the day-ahead market. However, the two-settlement system provides the same real-time incentives to price-taking consumers, as if they were purchasing all of their electricity at the real-time prices (cf. Chapter 3–2 of Stoft, 2002).

[4] The value of demand response on mitigating the variability of renewable generation has received some recent attention (Rahimi & Ipakchi, 2010; Stadler, 2008).