ELECTRICITY MARKETS INCENTIVIZE TECHNOLOGY MODULARIZATION

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Abstract

We study economic incentives provided by space-time dynamics of wholesale day-ahead and real-time electricity markets. Specifically, we seek to analyze to what extent such dynamics can promote decentralization of technologies for generation, consumption, and storage (which are essential to obtain a more flexible power grid). Our analysis is based on a technology placement problem that seeks to find optimal locations for generators and loads in the network that minimize profit risk. We show that an unconstrained version of this problem can be cast as an eigenvalue problem. Under this representation, optimal network allocations are eigenvectors of the space-time price covariance matrix while the eigenvalues are the associated profit variances. We construct a placement formulation that captures different risk metrics and constraints on types of technologies to systematically analyze trade-offs in mean profit and risk. Our analysis reveals that complete mitigation of risk is only possible by simultaneous investment in decentralized generation and loads (which can also be achieved using battery or microgrids). We thus conclude that space-time market dynamics indeed provide incentives for strategic diversification.

Keywords

Electricity Markets, Modularization, Space-time Dynamics.

Introduction

Decentralization of electricity generation, consumption (loads), and storage is an on-going trend in the power industry. From the perspective of an independent system operator (ISO), decentralization is desirable as it can provide spatial flexibility to control network flows and to overcome limited transmission infrastructure. In addition, large centralized facilities can become liabilities during extreme weather or attack events. Another issue associated with large centralized facilities is that they provide limited investment flexibility, which is often desirable to mitigate risks in electricity prices and policy. The need to mitigate such investment risks is promoting the development and deployment of smaller-scale (modular) technologies. On the other hand, it is well-known that large centralized facilities benefit from economies of scale.

Because the electricity price of large facilities can be a significant fraction of their total operating revenue/cost, price fluctuations in space and time represent important risks that affect both investment and operating decisions. Large companies often purchase electricity on the Day-Ahead Energy Market (DAM) as opposed to the Real-Time Energy Market (RTM) to minimize risk, as the former is far less volatile. The volatility of the electricity prices in RTM is illustrated in Figure 1. Here, we show the price change over 20 minutes for a specific day in California. Here, we see that, under a 20-minute period, the average electricity price jumps from 48.42 USD/MWh to 592.33 USD/MWh and then falls down abruptly to 35.15 USD/MWh. Here, we also see that such fluctuations are less abrupt at some network locations. Price volatility is less severe in day-ahead markets. We capture the space-time dynamics in a price data set that is capture in a matrix $\prod \in \mathbb{R}$. Here, the number of columns n is the number of spatial network locations (nodes) and the number of rows m is the number of time points. The price at the spatial location (network node) j is modeled as a random variable (denoted as P_j) and we use $P = \{P_1, \dots, P_m\}$ to denote a random vector containing all node prices. Consequently, the matrix entry $\Pi_{i,j}$ is interpreted as the i-th time realization of the price P_j and we assume that the probability of the realization is $1/m$ (we ignore temporal price correlations). We use this data to construct a space-time covariance matrix Σ for both DAM and RTM.

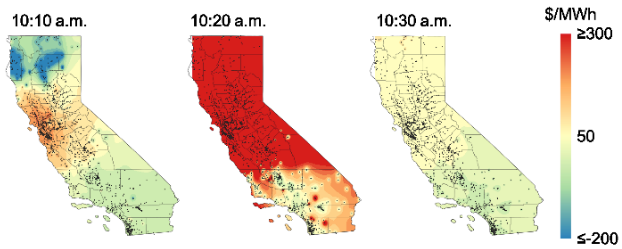

Figure 1. Electricity price fluctuation in RTM on February 5, 2015 in CAISO

We use basic statistical analysis to compute space-time price averages and standard deviations for the California Independent System Operator (CAISO) data for the year of 2015. This data set includes complete electricity price profiles for the year at 2,234 different network locations. The data set contains over 19,569,840 price points for DAM (one-hour time resolution) and 234,838,080 price points for RTM (5-minute time resolution). Our analysis finds that the RTM is significantly more volatile than the DAM in both space and time (see Figure 2). We also derived a placement formulation to identify optimal locations for loads and generators in the network that minimize profit variance (a standard risk measure). We define a loading vector $w \in R^n$ and the profit function $\varphi(w, P) := w^T P = \sum_{j \in \mathcal{N}} w_j P_j$ and note that this is a random variable. We interpret a positive loading $w_j > 0$ as an injection of power (generation incurring revenue for a positive price) and a negative loading $w_j < 0$ as a withdrawal of power (load incurring cost for a positive price). The optimal placement problem consists of solving the loadings w that minimize the profit variance and can be stated as:

$$\min_{w} \ \Sigma_{\varphi}(w) \tag{1}$$

By default, we assume that the optimal loading vector (denoted as w_1^*) satisfies the constraint $||w_1^*||_2 = 1$ (it is a vector of unit length), where $||\cdot||_2$ denotes the Euclidean norm. A unit-length loading vector can be interpreted as the allocation of one unit of power in the network nodes. A key observation that we make is that the profit variance is related to the price covariance as $\Sigma_{\varphi}(w) = w^T \Sigma w$. Consequently, the optimal placement problem is an *eigenvalue problem*. Accordingly, the optimal allocation vector w_1^* is the eigenvector corresponding to the minimum eigenvalue λ_1^* of the price covariance matrix Σ. Moreover, the minimum eigenvalue is the minimum profit variance $\lambda_1^* = \Sigma_{\varphi}(w_1^*)$. We extended the placement formulation to incorporate constraints on technology types and to perform trade-off analysis between expected profit and variance. Our analysis reveals that diversification of loads is necessary to mitigate risk. As expected, however, diversification comes at the expense of lower mean profit (see Figure 3).

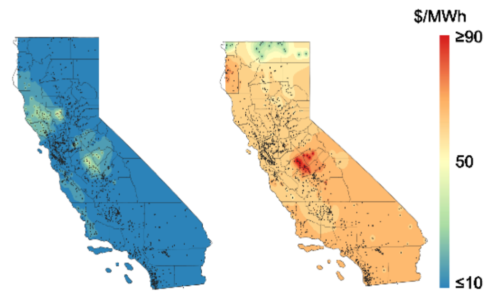

Figure 2. Temporal price volatility (at different spatial locations) for DAM (left) and RTM (right).

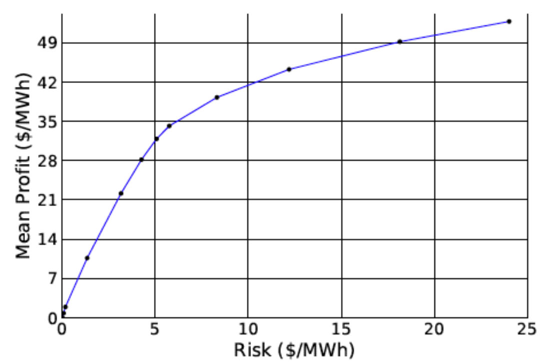

Figure 3. Mean profit vs. risk trade-off for DAM.

Acknowledgments

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