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Economic efficiency of coordinated multilateral trades in electricity markets

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Abstract

This paper presents economic efficiency evaluation of electricity markets operating on the basis of a coordinated multilateral trading concept. The evaluation accounts for the overall costs of power generation, network losses, and system and unit constraints. We assume a non-collusive oligopolistic competition. An iterative Cournot model is used to characterize the competitive behavior of suppliers. A supplier maximizes the profit of each of his generating units while taking rivals' generation as given. Time span is over multiple hours. This leads to a mixed integer non-linear programming problem. We use the augmented Lagrangian approach to solve iteratively for globally optimal schedules. An IEEE 24-bus, 8-supplier, and 17-customer test system is used for illustration. The results show that such a market at times of light demands exhibits little market power, and at times of large demands exhibits a great deal of market power. This contrasts with the PCMI and HHI concentration measures, which give fixed measurement values of market power. The results of two-year (730 round) market simulations show a range of deadweight efficiency loss between 0.9 and 6% compared to that of PoolCo which results in a range between 0.5 and 10% for the same test case.

Keywords: Economic efficiency; Coordinated multilateral trades; PoolCo; Electricity markets; Deadweight efficiency loss

1. Introduction

Major structural changes are sweeping the electric power industry in the United States. A driving force is to increase competition and open transmission access between states. Within the states, large efforts are being made to restructure local power industries. An emerging model is being implemented in the state of California. In this model, there is an energy marketplace composed of a power exchange (PX), brokers, and an independent system operator (ISO). Undoubtedly, this new structure will continue to evolve. To gain insights into this evolution, we study two basic organizational concepts: PoolCo presented in Refs. [4,13] and the coordinated multilateral trading (CMT) formalized by Wu and Varaiya [14].

The concept of the CMT leads to a decentralized market. Suppliers and customers arrange their trades independently or through brokers. Brokers and the ISO coordinate with each other to meet transmission constraints, achieve economics and allocate losses. This concept was shown to achieve economic optimality under the assumption of perfect competition: competitors have no market power and are willing to participate in profitable trades. Wu et al. used a 3-bus system to show the result. If there is a degree of market power, however, economic optimality may not be achieved.

Much research has shown that market power is a key issue in existing and emerging electricity markets [6,9,15]. Market power can be characterized by a measure of market concentration such as the Herfindahl–Hirschman index (HHI) or by a measure of the price–cost margin index (PCMI) (often referred to as the Lerner index). The HHI measures the effective number of suppliers in a market. The PCMI, on the other hand, measures the degree to which prices exceed marginal costs. These measures were noted to be inadequate [6,12]. The modeling approaches, mainly, simulate markets as if elasticity of demand and market shares are known. The result of these measures is fixed and does not capture market variations. Ref. [12] presents a market power index as a ratio of the forecasted and total available supply. Meanwhile, the deadweight efficiency loss is a standard for evaluating economic efficiency. It is equal to the difference between the optimal social welfare and the social welfare due to market power. As

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market conditions vary, the deadweight loss varies accordingly.

This paper presents an evaluation of the economic efficiency of the CMT concept. We set up a detailed market model. The model includes the overall costs of power generation, network losses, and system and unit constraints. We assume a non-collusive oligopolistic competition. An iterative Cournot model is used to characterize the competitive behavior of suppliers: a supplier maximizes the profit of each of his generating units while taking rivals' generation as given. Time span is over multiple hours. This leads to a mixed integer non-linear programming problem. The inclusion of network losses and costs has an important impact on the solution methods to be applied to this problem. Optimal scheduling of a generating unit depends on scheduling of other units. We use the augmented Lagrangian approach presented in Refs. [1,2] to solve iteratively for globally optimal schedules. The references mainly represent the main results of the approach and associated computational procedures for solving the hydrothermal scheduling problem.

The paper is organized as follows: an overview of definitions and notations is given in Section 2. Section 3 introduces a modeling framework. Economic and PoolCo system evaluation is discussed in Section 4. Section 5 presents the results of a test case. A comparative discussion between PoolCo and CMT markets is given in Section 6. The paper is finally concluded in Section 7.

2. Conceptual framework for energy markets

We consider an energy market with n_c customers and n_s suppliers sharing n_g generators. A demand at the kth customer load bus, during hour t is denoted by $d_k(t)$. Customer k's total benefit accrued from $d_k(t)$ is then $B_k[d_k(t)]$, where B_k denotes a benefit function and is assumed quadratic as developed in Ref. [11]. The marginal benefit defines demand as a function of price ρ. The sum of demands at the individual customer load buses, during hour t, gives the system total demand and is denoted by $D(\rho, t)$. We approximate D over a locally defined region by a linear function, as

$$D(\rho, t) = b_1(t)\rho + b_2(t) \tag{1}$$

where $b_1(t)$, $b_2(t)$ define time-varying coefficient. The demand function is an important input to the framework for evaluating the system economic efficiency.

The power generated by unit i during hour t is $g_i(t)$. We use $\mathrm{STC}_i(\tau_i^{\mathrm{off}})$, $\mathrm{SHC}_i(t)$, $C_i[g_i(t)]$, and $\mathrm{MNC}_i(t)$ to denote the cost associated with start-up, shut-down, normal operational, and maintenance of a thermal generating unit i. The unit constraints are:

1. Generation bounds: $\underline{g}_i \le g_i(t) \le \bar{g}_i$
2. Minimum up and down times: T^{on} and T^{off}.
3. Ramp up and down limits: $g_i(t) - g_i(t-1) \le \mathrm{UR}_i$ (up rate limit) and $g_i(t-1) - g_i(t) \le \mathrm{DR}_i$ (down rate limit)

The electric power is wheeled over a transmission network. The network has n_l lines interconnected by n system buses. The underlying system constraints are:

1. Generation-load balance $\sum_i g_i(t) I_i(t) = \sum_k d_k(t) + l(t)$, where $I_i(t)$ is on/off state of the ith unit and $l(t)$ is the network loss.
2. Spinning reserve requirements $\sum_i \bar{g}_i\, I_i(t) \ge \sum_k d_k(t) + r(t)$, where $r(t)$ is the allocated spinning reserve.
3. Emission bounds $\sum_t \sum_i \mathrm{ER}_i H_i(g_i(t))\, I_i(t) \le \mathrm{EM}$, where ER_i is the emission rate in lb/Mbtu, H_i is heat function and EM is the emission allowance.
4. Transmission line limits. $\underline{z}_m \le z_m(t) \le \bar{z}_m$, where z_m is the power flow of line m.

We study the market over n_T hours in the planning horizon T. The social welfare is defined as the sum of customer benefits minus the costs of power generation and transmission. By optimizing the social welfare, we obtain the optimal schedules of bus prices, unit generation and customer demands over T. We use the notation $(\varrho, g, d)^{\mathrm{Economic}}$ to denote the optimal economic schedules, where ϱ, g and d are $n_T \times n$, $n_T \times n_g$ and $n_T \times n_c$ matrices of bus prices, generators' output and bus loads, respectively. Given unit cost characteristics and customer benefits, we use the augmented Lagrangian approach presented in Refs. [1,2] to solve iteratively for the system optimal economic schedules. For a given set of load bus prices, demands are determined. For these demands, the system is scheduled at a minimum cost. Based on these schedules, we compute the clearing prices. Using these prices, bus demands are computed again. The process continues until convergence is observed [3].

When there is a strategic behavior exercised by generation suppliers or large customers, the trading process will result in price and power schedules which may not give the optimal social welfare. This leads to a deadweight efficiency loss. We use this loss to measure the economic efficiency of such a market. The market strategic behavior can also be characterized by a measure of market power such as the PCMI or a measure of market concentration such as the HHI. The PCMI, often referred to as the Lerner index, measures the degree to which prices exceed marginal costs. The HHI measures an effective number of suppliers in a market. These measures were noted to be inadequate [6,12]. The modeling approaches, mainly, simulate markets as if elasticity of demand and market shares are known.

3. Economic efficiency evaluation

Fig. 1 shows our proposed process model for the economic efficiency evaluation of the CMT. In this market, generation suppliers and customers trade independently.