ELSEVIER

Electrical Power and Energy Systems 26 (2004) 281–289

ELECTRICAL POWER & ENERGY SYSTEMS

www.elsevier.com/locate/ijepes

Economic efficiency of pool coordinated electricity markets

Salem Al-Agtash[a,*], Renjeng Su[b]

[a]Department of Computer Engineering, Yarmouk University, 21163 Irbid, Jordan
[b]Department of Electrical and Computer Engineering, University of Colorado, Boulder, CO 80309, USA

Received 12 December 2002; revised 11 August 2003; accepted 30 September 2003

Abstract

This paper presents economic efficiency evaluation of pool coordinated electricity markets. The evaluation accounts for the overall cost of power generation, network losses and costs, and various operational constraints. We assume a non-collusive oligopolistic competition. An iterative supply function model is used to characterize the competitive behavior of suppliers. A social welfare function is defined for PoolCo market that operates over multiple hours time span. This leads to a mixed-integer non-linear programming problem. An Augmented Lagrangian approach is used to solve iteratively for global optimal operation schedules (i.e. power generation, load, and price for each bus node) while considering constraints of different sorts. An IEEE 24-bus, eight-supplier, 17-customer test system is used for illustration. The results show deflection of electricity prices from the marginal costs of power generation. The results of 2-year (730 round) market simulations show a range of deadweight efficiency loss between 0.5

Keywords: Economic efficiency; Pool coordination; Electricity markets

1. Introduction

Electric power industries in the US and abroad are moving toward an era of restructuring. A general trend in many countries (e.g. New England, Chile, Argentina) is to have a mandatory power pool. This is referred to as PoolCo. The pool centrally schedules generators based on their bidding strategies to meet consumer requirements. It determines market-clearing prices, operates and controls the entire system, and maintains reliability.

Much current research is concerned with the general behavior of electricity spot markets. Various references (e.g. [15,22,23]) critically analyzed PoolCo structure advocated by Ref. [12]. Ref. [16] presents analyses for estimating prices of a pure PoolCo market with identical profit-maximizing generating firms. The results of the analysis give different measures of the price–cost margin index (PCMI) as a function of the number of identical firms, the level of capacity non-availability, and the accuracy of demand forecasts. The authors of Refs. [8–10] analyzed the UK electricity market using a supply function equilibria (SFE) model. The model gives competitive behavior of suppliers in meeting time-varying demands. The work was first developed in Ref. [14], for studying suppliers' competitive behavior under uncertain demand. For the purpose of characterizing the market behavior at the industry level, the UK market was modeled as a duopoly market, thus the work closely follows Klemperer and Meyer's formulation and conclusion for a homogeneous product. Green et al.'s study shows a range of equilibrium supply schedules for symmetric duopolists. Assuming no capacity constraints, it was concluded that no asymmetric SFE exist and that the market behavior characterized at the industry level differs very little between symmetric and asymmetric duopolistic markets.

The SFE model has been extended in Ref. [5] to account for a competitive fringe and several strategic players. The results show that a piece-wise affine SFE exists for linear demand and non-negative generation limits, under the assumption that bidders submit either affine supply functions or piece-wise supply function with relatively small pieces. The assumption of bidders submitting a supply function with small number of pieces has been relaxed in Ref. [6]. The authors analyze the properties of the equilibrium and numerically estimate

* Corresponding author. Tel.: +962-2-721-1111; Fax. +962-2-727-4725.

E-mail address: alagtash@yu.edu.jo (S. Al-Agtash).

0142-0615/$ - see front matter © 2003 Elsevier Ltd. All rights reserved.
doi:10.1016/j.ijepes.2003.09.001

candidate equilibrium supply functions by iterating in the function space of allowable bids. Refs. [7,11,17,18,20] have also applied the SFE model to analyze the electricity market under different assumptions and with different successes.

Based on such modeling aspects, one can easily obtain an estimate of the deadweight efficiency loss as a standard for evaluating economic efficiency, or an estimate of the PCMI as a measure of the exercise of market power. It has been argued in Ref. [4] that the Herfindhal–Hirschman index and PCMI measures of market power are fixed and do not capture market variations. The models of market analyses so far, either consider competition at the industrial level [8–10], or competition among identical generating firms [16]. Furthermore, these analyses do not account for the competitive behavior of individual diverse generation resources, network losses and costs, and the various system and unit operational constraints. All these have major impacts on the economic efficiency of such markets.

In Ref. [4], the economic efficiency evaluation has been presented in electricity markets operating on the basis of a coordinated multilateral trading concept. In this paper, we present an evaluation approach of PoolCo-based electricity markets. The evaluation accounts for the overall cost of power generation, network losses and costs, and various operational constraints. We assume a non-collusive oligopolistic competition. A social welfare function is defined for PoolCo market that operates over multiple hours time span. This leads to a mixed-integer non-linear programming problem. The Augmented Lagrangian approach presented in Refs. [2,3] is used to solve iteratively for global optimal operation schedules (i.e. dispatch of resources and system loads and determination of hourly market-clearing prices) while considering constraints of different sorts. The references mainly present the main results of the approach and associated computational procedures for solving the hydrothermal scheduling problem.

The paper is organized as follows: Section 2 defines an energy marketplace. An evaluation modeling framework is introduced in Section 3. Section 4 presents results of a test case. The paper is concluded in Section 5.

2. An energy marketplace

In an energy marketplace, let the number of consumers (a consumer is meant to represent a group of consumers drawing power from a load bus) be n_c and the number of generators be n_g. A kth consumer has a power demand $d_k(t)$ MW (Mega Watts), during hour t. An ith generator produces $g_i(t)$ MW, during hour t. The transmission network has n_l lines interconnected by n system busses. We study the market over n_T hours in the planning horizon $\mathcal{T}$.

2.1. Supply side

We assume a supplier's behavior is to maximize profit. A supplier's profit from generator i is defined as

$$\pi_i = \text{Revenue}_i - \text{Cost}_i \tag{1}$$

For a thermal generator i, the cost includes: start-up, shut down, normal operational, and maintenance costs denoted by $\text{STC}_i(t)$, $\text{SHC}_i(t)$, $C_i[g_i(t)]$, and $\text{MNC}_i(t)$, respectively. Operational costs of hydro resources are generally small. We denote the sets of thermal and hydro generators by $\mathcal{N}_\text{t}$ and $\mathcal{N}_\text{h}$. The set of all generating units is $\mathcal{N}_\text{g}$.

Cost models. The start-up and production cost models of thermal units are well formulated in the power engineering literature. We use the cost models given in Ref. [21]. In particular

$$C_i[g_i(t)] = \alpha_{1i} g_i^2(t) + \alpha_{2i} g_i(t) + \alpha_{3i}, \qquad \forall i \in \mathcal{N}_\text{t} \tag{2}$$

where α_{1i}, α_{2i}, and α_{3i} are constants. Units operate under various constraints: generation bounds, minimum up and down times, and ramp up and down limits.

2.2. Consumer-side

We assume consumers adjust their demands to maximize their net benefits, namely benefits minus payments. All are measured in dollars. During an hour t, the benefit of consumers from receiving $d_k(t)$ power demand at bus k is $B_k[d_k(t)]$. Suppose that the market price at bus k is $\rho_k(t)$, then consumers' behavior is defined by

$$\max_{d_k(t)} [B_k[d_k(t)] - d_k(t)\rho_k(t)] \Rightarrow \frac{\partial B_k[d_k(t)]}{\partial d_k(t)} = \rho_k(t) \tag{3}$$

Benefit model. A model for consumer benefits used by Schweppe et al. [19] is of the form

$$B_k[d_k(t)] = B_{k0}(t) + \rho_{k0}(t)[d_k(t) - d_{k0}(t)] \times \left\{1 + \frac{d_k(t) - d_{k0}(t)}{2\epsilon_k(t) d_{k0}(t)}\right\}$$

where $d_{k0}(t)$ is the nominal demand level at bus k; $B_{k0}(t)$ represents benefits when $d_k(t) = d_{k0}(t)$; $\rho_{k0}(t)$ is the nominal price at bus k; and

$$\epsilon_k(t) = \frac{\rho_{k0}(t)}{d_{k0}(t)} \frac{\partial d_k(t)}{\partial \rho_k(t)}$$

is a price elasticity at bus k. The above equation can be rewritten as

$$B_k[d_k(t), t] = b_{1k}(t) d_k^2(t) + b_{2k}(t) d_k(t) + b_{3k}(t) \tag{4}$$

where b_{1k}, b_{2k} and b_{3k} are time-varying coefficients. Assuming this benefit model and using Eq. (3), the demand function of the k consumer is linear in price and is given by

$$d_k[\rho_k(t), t] = \frac{\rho_k(t) - b_{2k}(t)}{2b_{1k}(t)} \tag{5}$$