ELSEVIER

European Journal of Operational Research 130 (2001) 156–168

EUROPEAN JOURNAL OF OPERATIONAL RESEARCH

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Theory and Methodology

Strategic gaming in electric power markets

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Received 9 December 1998; accepted 20 January 2000

Abstract

This paper presents an overview of strategic gaming used for understanding the effective company and regulatory strategies for various market participants under alternative scenarios on pricing and institutional structures for electric power. Utilizing the England and Wales (E&W) power pool as a testbed, we develop an aggregate model of payoffs for various stakeholders, under specified demand and supply scenarios, with strategic moves by these stakeholders as the key input to be evaluated. The use of this type of model in a strategic gaming setting is then examined, together with a discussion of experience in using this approach in evaluating a particular decision problem regarding network investment strategies in the E&W power market. © 2001 Elsevier Science B.V. All rights reserved.

Keywords: Energy; Strategic gaming; Contracting; Bidding

1. Introduction

Many problems of the on-going restructuring in the electric power sector are analytically intractable in the absence of strong and arguably unrealistic assumptions. This is primarily the result of the complexity of strategic interactions among the many participants in the electricity sector, and the complexity of faithfully modeling the underlying physical laws governing electric power for a major power system (Fernando and Kleindorfer, 1996). For this reason, and because of the natural desire to test ideas in realistic settings before institutional commitments are concretized, experimental and gaming approaches have been developed for a variety of settings. These have been used to shed light on bidding behavior (Rassenti and Smith, 1998) for power exchanges, on maintenance scheduling for transmission lines (Langdon, 1997), and are evident through the growing number of bidding and simulation games on the internet (e.g., Power World, http://powerworld.tech.com/features.html). This paper is in this "tradition". The authors developed a general model called Electric Power Strategy Simulation Model (EPSIM) to support role-playing and strategic gaming for participants in a typical power market. EPSIM

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PII: S0377-2217(00)00048-5

was initially used to evaluate alternative regulatory and contracting scenarios in the England and Wales (E&W) power market, where power sector restructuring was first implemented. The approach has also been implemented to examine several other strategic decisions in other power markets.

The purpose of the model developed is to capture the effects on network performance for the stakeholders involved in alternative investment, pricing and contracting strategies at a sufficient level of detail to allow a meaningful assessment of these strategies. In one sense, the model developed is simply a mechanism for determining stakeholder payoffs for the (very complicated) strategic investment, pricing and contracting game played by the power market participants. However, the benefits of using this model in the developing and understanding of the structure and interactions in this game can be significant, as we show by way of a case study of an important strategic decision concerning network investment and contracting behavior for the transmission service provider (the Grid Operator) in E&W power pool in the face of alternative regulatory regimes.

The basic message of the paper is that complex operational interactions, such as day-to-day trading, scheduling and despatching in a power pool, can be captured in an optimization model such as EPSIM, and this platform can then serve as an effective vehicle for evaluating the more complex interactions of stakeholders as they make strategic choices on network size, new investments and contracting terms. Using a strategic gaming framework in this fashion thus achieves both reasonable precision in outcome prediction of underlying operational quantities as well as a vehicle for testing robustness and optimality of strategic decisions. While this message is not new in the strategic gaming area (e.g., see Shakun 1972; Rao and Shakun, 1972), the expanding scope and complexity of problems that can be addressed in this manner is clearly worth documenting.

The rest of this paper is organized as follows. Section 2 provides an overview of the planning problems confronted by various participants (generators, transmission operators, distribution companies, customers, and regulators) in the electric power market, with special emphasis on the E&W power pool. In Section 3, we describe the model that was implemented through EPSIM, including handling the interactions of various pool rules and contracting decisions among market participants. Section 4 describes an application of EPSIM in a strategic gaming context to evaluate the robustness of alternative network investment and contracting strategies. Essentially, senior managers and technical staff for the Grid Operator (the National Grid Company or NGC) of the E&W power market participated in this gaming application by playing various roles of participants in the market to determine the robustness and profitability of alternative strategies as evaluated by EPSIM. Drawing conclusions from a single case study is always problematic. Nonetheless, the experience gained here suggests that the models such as EPSIM, building on decades of advancement in OR modeling/software and interface technology, can be important ingredients in real-time support of senior management decision making in arenas, which until now have been judged to be too complex to be supported by anything other than the traditional strategic planning process. In our conclusions, we suggest some possible areas for extending this work, focusing on areas of market development in electric power that seem especially appropriate for a strategic gaming framework because of the lack of accessibility of these areas to standard analytical approaches.

2. Restructuring and strategic choices in electric power markets

The strategic environment of interest in this paper is by no means unique to electric power. Across the globe, the decade of the 1990s has seen wave upon wave of privatization and restructuring of formerly monopoly network industries, beginning with airlines and telephony and then encompassing the energy and water sectors, and now spreading to such sectors as the post office, ports and waste disposal. In each of these sectors the new private operators face significant uncertainty and complexity in formulating their strategic plans. This arises not just because of the complexity of the sector itself, but because many of the participants in the sector are new and have unclear motives and no history to use as a basis for predicting their behavior in the new market place. This paper suggests an approach to support strategy in this environment, viz., the use of strategic gaming with properly validated OR models serving as the core to evaluate participant strategies. We focus strictly on electric power and rather specifically on the E&W power pool in the mid-1990s as our application testbed, but the approach suggested is intended to be considerably more general.

The key issue facing participants in the electric supply industry during this period was "unbundling". This means separating the value chain of electricity supply into its components of generation, transmission and distribution. Each of these components is separated and put under separate ownership. The model in the UK, which served as the precursor and beacon for other unbundling initiatives elsewhere, demonstrates the key elements of this unbundling. First, the generation sector is intended to be competitive, with free entry and exit. The distribution sector consists of a number of local franchises, each with regulated prices. The transmission sector is also regulated and has the responsibility of constructing and maintaining the transmission network and of scheduling and despatching generators to distribution loads according to least-cost principles. This last role of the transmission operator is known in the industry as the role of Grid Operator (sometimes referred to as the Independent System Operator). The strategic gaming application we will describe was focused primarily on the transmission operator (in the E&W pool, this is the privately owned, for-profit company National Grid Company, or NGC), but the roles of other stakeholders had to be modeled as well in order to provide a realistic testbed for the Grid Operator's strategic decisions.

Let us first note the strategic environment of NGC during the period of interest here. NGC and the distribution companies (Regional Electric Companies in the UK jargon) were facing increasing stringent regulation in the mid-1990s at the time this study was undertaken. A central issue in regulation is to align the incentives of the regulated company to operate efficiently while also assuring a reasonable level of profit for the company. In the UK context, these issues were especially pressing during the mid-1990s, since there was continuing concern as to whether privatization and early regulatory structures introduced in 1990 had been leading in the right direction. In particular, there was a widespread belief that the newly privatized companies that had arisen in the restructured power sector were garnering supernormal profits and that the consumers had not benefited significantly from the restructuring (see, e.g., Newbery, 1995; Wolak and Patrick, 1997; Wolfram 1999). Thus, it was expected that upon review of the price cap and revenue cap periods, which expired in 1995 and 1996 for the Regional Electric Companies and NGC (the Grid Operator) significant adjustments would be undertaken to the respective regulatory formulae which determined prices and profits for these companies. (The formula in question is the famous $\mathrm{RPI} - X$ prescription, which prescribes that the prices, or revenues if applied to total revenues, for a certain set of services are not allowed to be increased at a rate faster than the Retail Price Index (roughly equivalent to the CPI in the US) minus the X factor. This, in effect, requires prices in real terms to decrease by X% per annum. For details on the implementation of the price caps in the UK and the US, see Crew and Kleindorfer (1986). One-time decreases on the order of 20% were, in fact, eventually put into place in 1995 and 1996 for both the RECs and NGC, with significant increases in the X factor (between 3% and 5%) as well. These changes rank with the most significant changes in regulatory price control in history.) Various restructuring and diversification proposals for the Gencos were also on the table at this time to attempt to promote stronger competition and erode market power in certain regions. Against this background, key issues for power sector participants at the time included the following:

1. How large an adjustment in the price-cap formula could reasonably be expected if the economic entities (the RECs and NGC) were required to continue to earn reasonable rates of return on their net assets? In particular,

how would the generators and customers fare under various implementations of the existing or proposed price and revenue caps in place for the RECs and NGC?

2. From the perspective of the Grid Operator, what would be the most effective manner of managing congestion in the transmission network (the two basic possibilities were to expand the network or to manage congestion better through transmission pricing and constraint management contracts)?

To answer these questions required not just an extrapolation of previous earnings or behavior of other market participants. Rather, a case needed to be put together for both the regulator and company strategic managers that would be both credible and robust to a whole range of uncertainties in demand, competition and technology that might reasonably affect the electric power industry over the following decade. Given the sheer complexity of this exercise and its importance for customers, companies and regulators, it was recognized that more than simple back-of-the-envelope calculations would be required to provide a legitimate foundation for strategic recommendations. This recognition gave rise to the EPSIM model described below.

3. The EPSIM model

This section introduces the implementation of the EPSIM model in the context of the E&W electric power market, subject to pool schedule, pool despatch and constraint payments as they existed in 1996. A brief summary of the pool rules is included as Appendix A; these rules have seen few changes over the decade of the 1990s, but are expected to change in significant ways in the future once the so-called revised electricity trading arrangements (RETA), scheduled for the fall of 2000, have been implemented. As will be evident from Appendix A, the particular protocols for the schedule, despatch and settlement are the central drivers of incentives for agents' strategies. The agents involved in this game include "Gencos" or generating companies, "Discos" or distribution companies, and the Grid Operator, which in the case of the UK is the National Grid Company (NGC), which also owns the key transmission assets and operates as a regulated profit-maximizing company. We now briefly describe the essential features of EPSIM used in the gaming experiments of interest.

Each day, generators (and potentially load management contractors) in the E&W power pool submit bids to the power pool administrator. These bids specify a bid capacity (MW) at a bid price (£/MW) and are good for the day after the next day. At the close of business, the administrator prepares 48 schedules of plants and load management options with the lowest bid prices to meet total projected system demand in every half-hour period in the day after the next day. A computer system, Generator Ordering and Loading (GOAL), then produces a least-cost generation schedule for the day as a whole, taking into account all plant limitations and generator bids. This procedure identifies what capacity is in each "unconstrained schedule" and determines 48 associated System Marginal Prices (SMP: the bid price of the marginal plant in the unconstrained schedule). The Grid Operator, which is the National Grid Company in E&W, schedules and despatches capacity to minimize the total system costs, subject to transmission constraints, using the predetermined unconstrained schedules, associated SMPs, and bid prices that are adjusted for any constraint management contracts between the Grid Operator and generating plants and load managers, as discussed further below. These bilateral constraint management contracts are intended to ameliorate and manage congestion costs efficiently. EPSIM models this system planning problem in a manner which approximates the actual schedule, despatch and planning procedures of the E&W pool, and then determines the resulting payments for each participant in the market. Our analysis will focus only on the Gencos and the Grid Operator, treating Discos and retail demand as exogenous, i.e., scenario driven.

The EPSIM, implemented in Excel 7.0® for Windows, models the E&W power grid as a simple 4-node, 3-arc electric power transmission system. This simple network approximation proved to be sufficient for the strategic planning purposes of this model (although EPSIM can support much more detailed networks). Fig. 1 shows a schematic of the simplified network.

The model forecasts the financial implications of generation and transmission investments and bilateral contract options under alternative regulatory regimes over 10 *planning periods* that can be of any duration, but the default duration is 1 year. Each planning period is comprised of six *periods* in which the capacity is scheduled and despatched to meet the demand at each node. Demand in these six periods represents an average daily load duration curve for each node/region. A typical set of load duration curves is shown in Fig. 2. These load duration curves can be thought of as a screening curve for the planning period.

EPSIM employs the same procedures to schedule and despatch capacity as the actual grid, but for fewer periods and for the simplified grid. (Rules employed by EPSIM are *not* identical to the actual grid rules. During the time the pool administrator determines 48 unconstrained schedules and associated SMPs for a given day and actual despatch in that day, generators have some other options to revise their bids. These issues of strategic unit commitment and capacity bidding have been of considerable interest in the recent literature on the E&W pool experience (e.g., Newbery, 1995; Wolak and Patrick, 1997; Wolfram, 1999). The details of these strategies are not reflected in the current implementation of EPSIM.) Bids and contracts are good for the entire *planning period.* For each of the six *periods* in each planning period, the EPSIM first determines the unconstrained schedule and SMP. This is done by sorting plants in the increasing order of bid price and scheduling until the total system demand is met. In the case of a bid price tie, southernmost plants are scheduled first. EPSIM then schedules and despatches capacity to minimize system costs using the linear programming formulation detailed below. Taking one period after the next, EPSIM then computes the cashflow implications for each agent in the market. In the case of the Grid Operator, these cashflows are influenced by scenarios representing regulatory constraints on the prices or revenues. In the case of the Gencos, cashflows result from the bidding, scheduling and despatching rules now to be described.

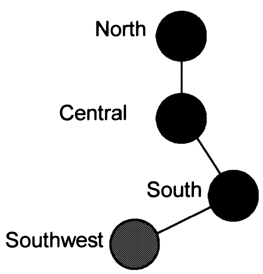

Fig. 1. Schematic of the simplified network in EPSIM.

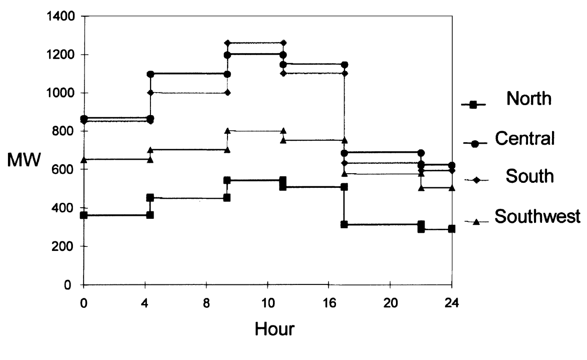

Fig. 2. Typical daily load duration curves (MW).

3.1. Mathematical programming formulation of the grid operator's schedule and despatch rules

Using the solver in Excel, EPSIM schedules and despatches capacity in each period to solve the following linear programming problem (see also Hobbs and Kevin, 1992, which does not include constraint-management contracts):

$$\begin{aligned}\underset{q_{ik},LM_{im},F_{ij},O_i}{\mathrm{MIN}} \Bigg[\sum_i \Bigg(\sum_k \Big(& \mathrm{SMP} \cdot q_{ik} \\ & + \big(\bar{p}_{ik} - \mathrm{SMP}\big) \cdot \big(q_{ik} - q_{ik}^{\mathrm{U}}\big) \\ & - R_{ik}\big(\bar{p}_{ik}, \hat{p}_{ik}, q_{ik}^{\mathrm{U}}, q_{ik}\big) \Big) \\ & + \sum_m \big(\bar{p}_{im} + \mathrm{SMP}\big) \cdot LM_{im} \\ & + (p_{io} + \mathrm{SMP}) \cdot O_i \Bigg) \Bigg] \end{aligned} \tag{1}$$

subject to generation and load management capacity constraints

$$0 \leqslant q_{ik} \leqslant \bar{q}_{ik}, \quad 0 \leqslant LM_{im} \leqslant \overline{LM}_{im} \quad \forall ik, im, \tag{2}$$

line capacity constraints

$$F_{ij} \leqslant L_{ij}, \quad F_{ji} \leqslant L_{ji} \quad \forall ij, \tag{3}$$

maximum forced outage constraints

$$0 \leqslant O_i \leqslant D_i \quad \forall i, \tag{4}$$

and the node balancing condition

$$\sum_k q_{ik} + \sum_m LM_{im} - \sum_{j \neq i} F_{ij} + \sum_{j \neq i} \left(1 - \alpha_{ji}\right) \cdot F_{ji} + O_i - D_i \geqslant 0 \quad \forall i, \tag{5}$$

where

$$R_{ik} = \left(\bar{p}_{ik} - \hat{p}_{ik}\right) \cdot \left(q_{ik} - q_{ik}^{\mathrm{U}}\right) \tag{6}$$

and where each node, i, contains demand, D_i, and can have k conventional generation plants with non-negative bid capacity, $\bar{q}_{ik}$ at non-negative bid price $\bar{p}_{ik}$, m multiple contracted outage options with non-negative bid capacity, $\overline{LM}_{im}$ at non-negative bid price $\bar{p}_{im}$, and forced outage, O_i that incurs a cost or welfare loss of p_{io}. SMP and the unconstrained schedule, q_{ik}^{U}, are determined before schedule and despatch. Primary decision variables are scheduled and despatched capacities, q_{ik} and LM_{im}, and resulting forced outage O_i. Power exports from node i to node j, F_{ij}, are limited by line capacity, L_{ij}. Power imports to node i from node j, $\left(1 - \alpha_{ji}\right) \cdot F_{ji}$, are also limited by line capacity, $L_{ji} = L_{ij}$, but incur linear line losses $\alpha_{ji}F_{ji}$ proportional to flow.

Essentially, this formulation represents the minimization of total costs borne by the Grid Operator, given pool rules. The minimization involves a trade-off between plants to be scheduled and despatched (at a cost equal to SMP per unit), plus constraint payments (discussed in detail below), minus refunds for constraint management contracts (also discussed below), plus payments to load serving entities for load management options, and payments for forced outage. The load management options LM_{im} may be thought of as reductions in the obligations to schedule and despatch power that are bid into the system by various wholesale demand points and that can be freely exercised (at the stated bid price) by the Grid Operator as needed. Note in (5) that these load management options at node i net against aggregate demand D_i. The constraints in this mathematical program reflect the total generation capacity and load-management options available, reflected in (2), transmission capacity constraints, reflected in (3), obvious upper bounds on outage, and the note balancing condition, which is just Kirchoff's Law at node i. Since (1) reflects the cash outlays for the Grid Operator (a regulated for-profit company), given bids by generators and load-serving entities, it is clear that the Grid Operator will and should attempt to minimize these outlays, subject to the physical, demand fulfillment and contractual obligations captured in the constraints to this problem. (The output of EPSIM was validated against actual aggregate flows and other observable or reported variables with errors on the order of 1% in predicting aggregate flows and their financial consequences.) The decision variables are scheduled and despatched capacity (q_{ik}), load management options exercised (LM_{im}), line flows (F_{ij}), and unfilled demand not covered by load management options (O_i).

The first term in (1) $\mathrm{SMP} \cdot q_{ik}$ reflects the "energy payment" from the power pool to plant k for the scheduled and despatched power at node i; the second term reflects the "constraint payment" from the Grid Operator, $(\bar{p}_{ik} - \mathrm{SMP}) \cdot \left(q_{ik} - q_{ik}^{\mathrm{U}}\right)$, that makes up the difference between the bid price and SMP. (Generators also receive a so-called capacity charge $\mathrm{CC} = \mathrm{LOLP}(\mathrm{VOLL} - \mathrm{SMP})$, where LOLP is the loss of load probability in the period in question and VOLL is the value of lost load, set at £2000/MWh. We do not include CC in the present model, since we are concerned with larger aggregate time periods and the SMP calculation provides a reasonable approximation to the actual pool price paid over the entire aggregate period. See Wolak and Patrick (1997) for further discussion of the capacity charge.) The third term in (1) reflects the payments to the Grid Operator by generators for power scheduled and despatched covered by constraint management contracts. Under existing rules, a contracted plant is obliged to refund $R_{ik} = (\bar{p}_{ik} - \hat{p}_{ik}) \cdot (q_{ik} - q^{\mathrm{U}}_{ik})$ to the Grid Operator when q_{ik} is scheduled and despatched, where $\hat{p}_{ik}$ is an exercise price specified in the contract.

Concerning the payments for load management options exercised by the Grid Operator, the final two terms in (1), contractors for load management services receive only a "constraint payment" from the Grid Operator at their bid price plus SMP, i.e., $\bar{p}_{im}$ + SMP. The cost of forced outage in each node is set very high (currently $p_{io} = £2000/\mathrm{MW}$ compared to average plant bid prices between £10 and £50/MW). Forced outage costs are also assigned to the Grid Operator, not to the power pool.

3.2. Negotiating contracts with generators

A central issue in any power pool is the magnitude and control of congestion costs. Such costs arise from transmission losses and from despatching generators that are not least-cost generators because of transmission constraints. In the E&W power pool, congestion costs are explicitly calculated through the constraint payments as represented in (1). In other power pools, congestion costs are calculated and collected through other mechanisms, e.g., Hogan (1992) or Chao and Peck (1997). The key issue in all power pools is to ensure that the Grid Operator is incentivized to invest in network enhancement and expansion, in ancillary generation support and in other areas under its control, to minimize total costs including the congestion costs under its control. Accurately capturing these economic costs is the basic point of the EPSIM model.

A fundamental driver of constraint payments reflecting congestion costs are the bids of generators. A generator owner, who knows that the generator faces transmission constraints, and may for this reason alone not be despatched, may bid a very low price, even zero. The owner then assures that the generator will be in the unconstrained despatch order, and will collect a large constraint payment (equal to SMP minus his bid price per MW per hour) when his generator is not despatched because of transmission constraints. Similarly an owner who knows that his generator will be despatched under almost all circumstances because lower priced generators will not be able to be despatched due to congestion constraints will bid a very high price, and collect an appropriate "constrained-on" payment. To provide incentives for the Grid Operator to negotiate with such owners, so that they do not engage in strategic bidding of the sort just described, the Grid Operator has the right to negotiate with individual generating facilities, to pay them a contract fee in return for the generators' agreement to a payment schedule that substitutes the terms of the contract for the terms of the pool rules. Through this means, the Grid Operator has the incentive to understand congestion cost trade-offs and to manage them via contracts, which we now discuss, to mitigate their constraint payment obligations.

Contracts come in two flavors: constrained-on (C-on) and "constrained-off" (C-off) (while actual contracts in the E&W power system may be made, withdrawn, or renegotiated for different length periods, in EPSIM, a contract is good for an entire planning period (modeled by a representative day)). Capacity that is *not* in the unconstrained schedule, but *is* despatched is said to be constrained-on. Capacity that *is* in the unconstrained schedule, but is *not* despatched is said to be constrained-off. A contracted plant receives an upfront option fee (in the form of a certain fee per MW contracted per year) in exchange for the obligation to refund the following payment to the Grid Operator whenever the plant is constrained-on (-off) according to the terms of the contract:

$$R_{ik} = \left(\bar{p}_{ik} - \hat{p}_{ik}\right) \cdot \left(q_{ik} - q^{\mathrm{U}}_{ik}\right). \tag{6}$$

This amount depends on the running price (RP) (an exercise price), $\hat{p}_{ik}$, specified in the contract. Contracts are exercised only if the plant is constrained in the fashion covered by the contract (various contract forms are discussed below).

Constrained-on contracts: Constrained-on contracts take effect only when the capacity is constrained on, $(q_{ik} - q^{\mathrm{U}}_{ik}) > 0$. Three forms of constrained-on contracts are allowed in practice (and in EPSIM):

- Under a *Pure SMP Constrained-on contract*, a plant agrees to take only the energy payments from the pool and to refund any C-on constraint payments to the Grid Operator. As such, the contract refund is specified by (6) with

$$\hat{p}_{ik} = \text{SMP}. \tag{7}$$

- Under a *MAX(RP, SMP) Constrained-on contract*, a plant agrees to use either SMP or a specified RP, whichever is greater, to determine C-on constraint payment refunds. As such, the contract refund is specified by (6) with

$$\hat{p}_{ik} = \text{MAX}(\text{RP}, \text{SMP}). \tag{8}$$

We illustrate the possible payment schedules for the marginal plant under this type in Fig. 3. Note that $\bar{p}_{ik}$ for the marginal plant sets SMP. If $\hat{p}_{ik} > \bar{p}_{ik} = \text{SMP}$ and the marginal plant has the capacity that is constrained-on, then the contract refund is negative, $(\bar{p}_{ik} - \hat{p}_{ik}) \cdot (q_{ik} - q_{ik}^{\text{U}}) < 0$, and the Grid Operator is obliged to pay this amount to the plant.

- Under a *Pure RP Constrained-on contract*, a plant agrees to use RP to determine C-on constraint payment refunds. As such, the contract refund is specified by (6) with

$$\hat{p}_{ik} = \text{RP}. \tag{9}$$

Under this contract type, from (6), if the marginal plant has capacity that is constrained-on, a refund may be due to the Grid Operator or the plant may be due to an additional payment.

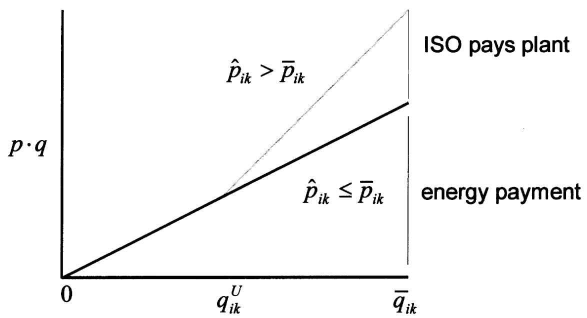

Fig. 3. Marginal plant net payment schedules for MAX (SMP, RP) C-On contract.

Constrained-off contracts: Constrained-off contracts take effect only when capacity is constrained off, $(q_{ik} - q_{ik}^{\text{U}}) < 0$. Two forms of constrained-off contract are used in practice:

- Under a *Pure SMP Constrained-off contract*, a plant agrees to take only the energy payments from the pool and to refund any C-off payments to the Grid Operator. As such, the contract refund is specified by (6) with $\hat{p}_{ik} = \text{SMP}$.
- Under a *MIN(RP, SMP) Constrained-off contract*, a plant agrees to use either SMP or a specified RP, whichever is less, to determine C-off constraint payment refunds. As such, the contract refund is specified by (6) with

$$\hat{p}_{ik} = \text{MIN}(\text{RP}, \text{SMP}). \tag{10}$$

Under this contract type, if $\hat{p}_{ik} < \bar{p}_{ik}$ and the marginal plant has capacity that is constrained-off, then $(\bar{p}_{ik} - \hat{p}_{ik}) \cdot (q_{ik} - q_{ik}^{\text{U}}) < 0$ and the Grid Operator is obliged to pay this amount to the plant.

The above lays the foundation for the evaluation platform used in the strategic gaming described below. The key element here is a faithful representation of the actual physical power flows, costs and cashflows accruing to various stakeholders in the power pool. Given this representation, and the ability to represent explicitly the bidding, contracting and investment options open to each stakeholder, a model like EPSIM can serve as a vehicle for one or other of the stakeholders to develop and explore their strategies and potential responses to these by other stakeholders.

4. Some strategic problems and scenarios

This section considers some illustrative examples of the use of EPSIM in support of regulatory and strategic policy evaluation. The two central issues we consider here are the effect of regulatory changes for the transmission service provider/Grid Operator and the effect of various investment and constraint-management approaches for the E&W pool. We already noted in Section 2 the context of the strategic environment going into the 1995–96 period. This was a period in which the electricity regulator (Office of Electricity Regulation (OFFER)) was scrutinizing all the profits of all the participants in the market, especially since several of these had made significant profits in the initial period of privatization in the early 1990s. We first describe the nature of the strategic gaming analysis undertaken, the players who participated and their roles. We then describe the strategic scenarios that were analyzed in this process and the results obtained.

4.1. The structure of the game

Players: There were typically five key players in this game (at times individual roles for various players were played by a team rather than a single individual): the first two players represented the two major generating companies (Power Gen and National Power); the third player represented all the other generators; the fourth player represented the Grid Operator (in this case, NGC), and the fifth player was the "Master of the Game" who set the scenario in place, including regulatory restrictions and demand growth patterns, as well as other parameters of the game. The first four of these players were selected from the senior management and staff of the group responsible in the Grid Operator for strategic planning. The fifth player (Magister Ludi) was one or other of the co-authors of this paper. (All of these players were university educated, some with advanced degrees, and had been with the Grid Operator since the early days of privatization, beginning in 1990, and several of them were seasoned veterans in the electric power industry.)

Strategies and Time Frame: The strategies of the Grid Operator were the location and magnitude of various network expansion/enhancement projects, as well as constraint management contracts, if any, proposed to generators. The effect of investment strategies would be to change the available transmission capacity (see (3)) beginning in the year in which the expansion became operational. Various small and large increment investment strategies were made available ex-ante to the Grid Operator, together with the cost information and increases to the asset base of the company should these strategies be implemented.

The strategies of generators were the bids for each of their generating facilities, which bids were assumed to hold for a single year. Generators were also free to accept or decline constraint management contracts offered to them by the Grid Operator. (None of the scenarios studied considered expansion of generator capacity, but generators were allowed to restrict available capacity should they wish to do so.) Given these bids, and the investment and operating strategies of the Grid Operator, EPSIM was used to simulate the payoffs to each player for a 10-year time horizon.

Incentives and Payoffs: For each scenario (see below for details), strategies were first determined by each player as inputs to EPSIM. EPSIM was then run, and the results of all the 10 years of performance simulation, as provided by EPSIM, were given to each participant, both in tabular form and graphically. The output was public in the sense that every participant was given the profit and cashflows for all the participants in the market, not just their own. They were also given the strategies (bids, investments and contracts) chosen by each player. (These are, of course, publicly observable in reality as well.) Players were asked whether they would like to revise their strategies, in the light of the information they had received. If any player wished to do so, new strategies were developed and the process was repeated until no further changes were desired by any player for that particular scenario. (Given this information and implementation procedure, the nature of the equilibrium that would be captured at least in a stylized manner is that of open loop, dynamic Nash play. Given the complexity of the strategy spaces and of the payoff function, it cannot be known at this point how close players actually came to Nash equilibria or best response strategies.) No cash was used to incent players, since these players were all members of the Grid Operator's staff or management team. However, players were very motivated to maximize profits in each of their respective roles since this was considered an extremely important strategic planning effort. While all of these players came from the Grid Operator, they recognized that the generators would be determining their bids and constraint contracts so as to maximize their own profits. Thus, it was emphasized throughout the exercise that a realistic response, i.e., a profit-maximizing response, was required to assure a proper understanding of the robustness or vulnerability of a particular Grid Operator strategies to countermoves by other players.

4.2. Scenarios examined

Two typical scenarios and results from this strategic gaming are now described.

Case 1: Average demand growth of 2%, peak demand growth at 0.5% over 10 years. No new generation or transmission capacity added. The regulatory regime examined was that which was in place in 1996 for the Grid Operator. This envisaged a revenue ceiling set to recover a fixed annual return on the net assets of the Grid Operator. The regulatory regime also specified a number of details in terms of the structure of the transmission and pool tariffs that were reflected in this scenario. The thrust of this case was to evaluate the likely impact on the Grid Operator and the Gencos of retail competition (introduced in 1998), which econometric studies indicate would have a strong effect in suppressing the peak demand growth through better pricing and metering signals. The second point of interest in this scenario was to evaluate the impact of alternative regulatory scenarios on the profitability of the Grid Operator and other participants.

Concerning the issue of an eroding peak (or a better load factor), the expected consequences for utilization and profitability of base load and peaking plant were observed, but these were significantly affected by transmission constraints and related constraint payments. In particular, absent new Transmission & Generating capacity, properly situated, constrained base-load plants in the North see at best small improvements in utilization, even though the "national load curve" is flattening. Moreover, because of the logic of constraint payments, profitability for the base-load plants may actually decrease because of decreasing SMP in response to load flattening and the logic of constraint payments for constrained-off plants (e.g., those in the North in this scenario).

Concerning alternative regulatory scenarios, more stringent price caps (on MWh zonal transmission prices) and revenue caps (on MW subscription fees levied on generators and on suppliers) have the expected effect of reducing profitability. The interesting point for the Grid Operator from the equilibrium runs of this scenario was the relative impact of moving to a stronger reliance on transmission charges based on net assets vs. a stronger reliance on charges related to the amount of energy transmitted. Various scenarios were run under many alternative conditions to evaluate this issue. The result of this evaluation was the rather robust finding that heavier reliance on MWh price cap regulation to raise necessary revenues would result in higher profitability for the Grid Operator than reliance on revenue caps related to the value of their net assets. This is rather intuitive when one considers the base case finding here of slowly growing average demand and no new investment in line capacity. The interesting fact is that this result continues to hold even when new transmission capacity is allowed, as long as one also allows the regulator to "true up" the revenue cap agreement periodically benchmarked on the overall financial results (based on returns on net plant which would change over time as new investment is added). The rationale again is intuitive (at least ex-post); new investments by the Grid Operator may result in a temporary addition to the "rate base" and resulting revenues, but these are countered by the regulator at the next review period in which the revenue cap is trued up to maintain an overall ROA.

Case 2: Similar demand and regulatory conditions were set to those of Case 1. In this case, however, the Grid Operator evaluated the optimality of various versions of the following two basic alternatives:

1. Expand transmission capacity to meet increasing demand (choosing from among various projects to enhance the capacity of interconnectors from North to South by 10% in 1998–2000).
2. Alternatively, use constraint-management contracts to reduce congestion costs and constraint payments.

In this case, the key point of interest is the management of constraint costs and payments by the Grid Operator in order to reduce out-of-merit despatch. Such out-of-merit despatch occurs for two reasons: transmission constraints (which can be relaxed by additional investment) and strategic bidding behavior by Gencos (which can be ameliorated by constraint-management contracts). Intuitively, the use of contracts is a much more flexible instrument than building new capacity. What the gaming exercise showed, however, is that whether such contracts can be negotiated depends on both the expected regulatory treatment of constraint revenues (are they separately negotiated and regulated or are they part of the aggregate bottom line of the Grid Operator) as well as on the perceived bargaining power of the agents involved. Consider, for example, a Genco with some market power in a particular region (say the South) which is currently bidding a very high price into the pool for a base-load plant with the sure knowledge that this plant will nonetheless be despatched (and paid a high congestion payment) since it is constrained on because of transmission constraints. If no new generation or transmission capacity is on the horizon for the near future, then that Genco will not be very interested in negotiating a constraint contract (say of a pure SMP-Constrained-on type). However, the very threat of new line construction or enhancement, or constraint contract negotiations with other Gencos, can alter the negotiation setting radically. By playing through alternative contract mixes and competitive reaction scenarios, the determinants of robust strategies for both profit and social welfare maximization were developed. (It is interesting to note that in the intervening period since these strategic games were developed, NGC has done an outstanding job of managing transmission constraints and the associated congestion costs. Mike Calviou, Market Issues Manager of NGC, reports that total NGC constraint costs have fallen from a high of over £200M in 1993/4 to a forecasted level of £20–30 M this year.)

The above cases provide some insight into the types of analysis which strategic gaming using a vehicle like EPSIM provides. As in other strategic simulation studies, the benefits are not so much for the analyst from the mostly intuitive results of a validated model, but rather from the learning that takes place through gaming interactions involving rational, motivated players who have a stake in the outcome of strategies. Other benefits in this case arose from developing a better understanding of alternative strategies for the design and detailed implementation of price and revenue cap regulations of various types in a fairly complex setting.

5. Conclusions

This paper has explored the use of strategic gaming to support the evaluation of business strategies and policy options in the evolving electric power market. Perhaps the most important message to take away from our experience to date is the importance of an accurate representation of the institutional details affecting the strategies of interest. In the case analyzed here, regulatory and bidding strategies for network investment were analyzed in the context of the E&W power market using the EPSIM framework. The key strategic elements affecting these options therefore concerned the structure of regulation and the operation of the E&W pool and related constraint-management contracts. A detailed evaluation of other strategic areas (e.g., generation, location and investment strategies, unit commitment rules, maintenance scheduling, reactive power and other ancillary generation support contracts) would require equally detailed modeling of other aspects of network operations.

The benefits of strategic gaming go well beyond evaluation, of course. Perhaps the most important benefit of strategic gaming is the learning for the executive team associated with strategy, especially in a competitive environment. The ability to "pretest" strategies in a realistic setting is not just a confidence-booster; it can be the difference between finding the high ground of robust profitability and steering into the cliffs of intense regulatory scrutiny and shareholder dissatisfaction.

In extending this preliminary analysis, several additional studies were undertaken. First, the EPSIM framework was applied to a large regional power pool in the United States with a central concern as to the impact of transmission congestion on market power of large, well-situated incumbents. Second the EPSIM model was used in evaluating the desirability of the joint Argentine–Chilean interconnection agreement, just completed in 1998–99, to determine both its economic feasibility and the likely strategic interactions of bidders on both sides of this interconnection. (For details on this latter study, see Brereton (1998).)

A final extension of this work concerns modeling of bilateral contracts between generators and distribution companies when transmission constraints make spot markets less than completely reliable. Following the structure of the EPSIM model, the theory of such bilateral contracts has been developed in Wu et al. (1999a,b). This work provides the theoretical foundation for continuing developments in restructuring power markets to allow new trading arrangements such as those under consideration for the UK power pool under RETA. Under RETA, existing pool arrangements will be further enhanced with a shorter-term bilateral market to enable market participants to fine tune their contract positions up to 4 hours ahead of market execution.

Acknowledgements

The authors gratefully acknowledge the assistance of Kevin Fitzgerald in programming the EPSIM software discussed herein. We also appreciated the assistance of National Grid Company (NGC) officials in clarifying existing Pool Settlement Rules. The opinions expressed in this paper are, however, entirely those of the authors and do not necessarily reflect the views of either current or past managers of NGC. Earlier versions of this paper were presented in the 33rd Annual Hawaii International Conference on System Sciences (Kleindorfer et al., 2000) as well as in INFORMS National Meetings, San Diego, 1997. The authors thank participants in both conferences as well as three anonymous referees for helpful comments.

Appendix A. Pool rules in the England and Wales power pool based on OFFER (1999)

The E&W power pool serves as the basis for a spot market, described in detail in Wolak and Patrick (1997) and Wolfram (1999). The OFFER has changed the Pool Rules a few times over the decade of the 1990s, but the basic structure of these rules has remained unchanged since their introduction with privatization in 1990. The most recent change took effect on 27 July 1998 and introduced strengthened rules on capacity charges to provide increased incentives to generators to maintain an adequate margin over the level of demand.

Generators sell power into the pool at pool purchase price (PPP) (SMP plus capacity payment) while suppliers buy from the pool at the pool selling price (PSP) (PPP plus Uplift). SMP is determined via an optimization program that determines the least-cost method of despatching generators to loads, given generator bids (in £ per MWh) and demand-side options for load curtailment, but ignoring transmission constraints. This schedule is called the unconstrained schedule. Uplift pays for a number of additional costs incurred on the day and includes unscheduled availability payments (payments to generating units that were available but not required to run) as well as additional generation costs resulting from differences between forecast and actual demand and between generator's forecast availability and actual availability. Payments are calculated for each half-hour during the day (settlement period). Generators are paid PPP. Suppliers pay at PSP. The pool must be financially balanced every day.

Discussion concerning the new trading arrangements developed under RETA is ongoing. Pool rules are expected to be significantly altered under RETA. OFFER will be publishing a set of detailed proposals for consultation shortly. (The planned implementation date is Autumn 2000.) The key element of RETA is the creation of a balancing market from about 4 hours ahead of despatch to enable NGC to balance in a cost effective manner generation and demand and to resolve any constraints on the transmission system by accepting bids to buy and sell electricity. There will be a settlement process for calculating a price to recover the costs of dealing with imbalances and for charging generators and suppliers who were out of balance. This would provide stronger incentives than at present for generators and suppliers to forecast and meet their commitments.

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