An Oligopolistic Power Market Model With Tradable NO_X Permits

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***Abstract*—Models formulated as complementarity problems have been applied previously to assess the potential for market power in transmission-constrained electricity markets. Here, we use the complementarity approach to simulate the interaction of pollution permit markets with electricity markets, considering forward contracts and the operating reserve market. Because some power producers are relatively large consumers of permits, there could be interaction between market power in the permits and energy markets. Market power in the energy market is modeled using a Cournot game, while a conjectured price response model is used in the permits market. An illustrative application is made to Pennsylvania—New Jersey—Maryland Interconnection (PJM), which we represent by a 14-node dc load-flow model, and the USEPA Ozone Transport Commission NO_x Budget Program. The results show that forward contracts effectively mitigate market power in PJM energy market and both simulated solutions of perfect and Cournot (oligopoly) competition are a good approximation to actual prices in 2000, except that the Cournot model yielded higher peak prices. The NO_x market influences the Cournot energy market in several ways. One is that Cournot competition lowers the price of NO_x permits, which in turn affects on low- and high-emission producers differently. In general, because pollution permits are an important cost, high concentration in the market for such permits can exacerbate the effects of market power in energy markets.**

***Index Terms*—Air pollution, complementarity, Cournot, economics, game theory, pollution, power generation economics, power market modeling, power transmission economics.**

I. Introduction

THE supply-side rationale for restructuring electricity markets is to create a competitive environment to enhance production efficiency, reduce prices, and provide incentives for efficient long-run investment in generation. On the demand-side, the hope is that restructuring will provide more accurate signals for consumers to adjust their consumption in response to cost variations. However, the achievement of these goals is hindered by political, technical, and economic factors, including the presence of market power in some markets. Market power is defined as the ability of market participants (i.e., suppliers or consumers) to unilaterally or to collectively manipulate markets in their favor [1], [2].

There are several reasons why market power is a particular problem in electricity markets. First, short-term demands for electricity are very inelastic, both as a result of the nature of commodity and lack of real-time metering. Second, network limitations lead to market separation if transmission lines are congested. Third, the shape of supply curves is such that marginal cost increases drastically where the price is usually determined during peak periods.

The consequences of market power can include price distortions, production inefficiencies, and a redistribution of income from consumers to suppliers. Many models have been developed to analyze market power in electricity markets (see reviews in [3]–[5]). Such models are used to assess the impact of changes in market design (e.g., type of transmission rights or geographic scope of allowances markets) and market structure (e.g., size of generating firms, amount of transmission capacity) upon prices and market efficiency.

Market power models generally take either an empirical or process modeling approach [4]. Which approach is appropriate depends in part on the question of interest. The empirical (or *ex post*) approach compares observed prices to a hypothetical competitive benchmark (marginal cost) to assess whether market power has been exercised. Supply costs and technology are usually represented by aggregated marginal cost curves. In contrast, the process modeling approach is used *ex ante* to assess the potential for market power under new or changed market designs or structures. Such models can build in considerable detail about generator characteristics, transmission constraints, locations of loads, etc.

Process models of oligopoly are usually based on the Nash equilibrium concept. Nash equilibrium prices can be calculated for several different types of strategies (e.g., quantity strategies for a Cournot-Nash game or price strategies for a Bertrand-Nash game). Then various comparisons can be made. For instance, estimated Nash prices can be compared with a pure competition scenario ($\text{price} = \text{marginal cost}$), or Nash prices under different market designs can be compared. Such Nash models are often criticized because of their simple assumptions about strategic behavior. However, the tractability and rich detail of process models can provide insights on prospective market, technology, and policy changes that that would be impossible to analyze in the empirical approach [4].[1]

An emerging issue in market power and market design has been the interaction of pollutant emissions permits markets and energy markets. USEPA and state agencies have created various cap-and-trade programs to control air pollution emissions [6], [7]. The programs first establish a cap on total regional or

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[1]Laboratory experiments, not discussed here, are an alternative approach to projecting the impact of such prospective changes.

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national emissions and then allocate permits to affected facilities. One unit of permit allows its holder to emit a fixed amount of pollutant, and permits can be traded in secondary markets. To make sure that an affected facility's emissions do not exceed the number of permits it holds, the facility can reduce pollution through operational or equipment changes, or purchase permits from other companies who have excess permits. Excess permits can be sold, or banked for future use. Examples of such programs include the national SO_2 emissions trading program of the 1990 Clean Air Act Amendments and the RECLAIM NO_x and volatile organic compound program of the Southern California Air Quality Management District [8]. In our application, we consider the Ozone Transport Commission (OTC) NO_x Budget program in the northeastern U.S., and its interactions with the Pennsylvania—New Jersey—Maryland Interconnection (PJM) energy market.

If permits are in short supply and there is significant market concentration, it may be possible for large generators to exercise market power in both energy and permits markets. Profit-maximizing strategies might differ for such firms when both markets are considered. For instance, empirical analysis of the 2000–01 power crisis in California suggests that a large generator put a cost-squeeze on other firms by intentionally consuming more permits than necessary, raising permit costs for other companies who were short of permits [9]. Permit shortages and high permit prices were reasons offered by some generators for their inability or unwillingness to generate power in the waning months of 2000.

However, while there are many models of market power in electricity markets, there are few models that consider interactions with tradable permit markets. A partial exception is a process model of pricing in the PJM market [10]. But in that case, the prices of SO_2 and NO_x permits were exogenous to the model, and their effects on electricity costs were included in production cost curves. The model did not determine permit prices endogenously, nor did it consider the possible exercise of market power in emissions markets. Another difference between that model and ours is that ours includes a network representation, so that market separation due to transmission congestion can be represented. If dominant firms exercise market power and withdraw generation, the impact on emissions is a function of where and what kind of substitute generation occurs. Without an adequate representation of transmission, estimates of costs, emissions, and prices could be distorted [11].

The purpose of this paper is to illustrate the ability of the process modeling approach to study the interaction of markets for power, transmission, and tradable emission permits in the presence of market power. A hypothetical application to the PJM energy and OTC NO_x markets illustrates the capabilities of the approach. Because the SO_2 allowances market is national in scope, we treat its price as exogenous. However, the NO_x market for the northeastern states is much smaller in size, limited (in 2000) to Connecticut, Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, and Rhode Island, so we treat its prices as endogenous. We include a linearized dc transmission network in our model and consider five electricity demand periods in a single ozone season (May–September). As a base case, we assume that there is no market power in both the NO_x permit and electricity markets. We then consider market power in the electricity market using the Cournot strategy assumption (similar to [3]), and in the NO_x market using the conjectured price response approach in which a generating company anticipates how changes in the number of permits it buys or sells affects the market price of those permits. The latter approach is similar to the conjectured supply function method of modeling oligopolistic energy markets [5], [12], in that each company is implicitly making an assumption about how other company's decisions (in our case, net permit purchases) will change on the margin as price changes. The impact of including NO_x conjectures in the model is discussed later in comparison with the pure Cournot case. We report price, cost, and emission effects along with various measures of economic efficiency, including consumer and producer surplus (profit) and total social welfare.

The remainder of this paper is organized as follows. In Section II, we give the mathematical formulation of model, including both pure competition and oligopoly. Then in Section III, we provide some background on the NO_x tradable permit program and PJM electricity market, as well as summarize the data sources used in our application. In Section IV, we report our results, while in Section V we provide some closing comments.

II. Model

The model is a multiple-period version of [3], elaborated to account for the NO_x budget program, forward contacts, and a operating reserve market. A theoretical analysis of the mathematical properties of the model, including uniqueness and existence of equilibria, is presented in [13], [31].[2] In the model, the NO_x budget program serves as a complicating constraint that creates an interdependence across periods; i.e., suppliers have to coordinate their output level over periods to ensure compliance with the seasonal NO_x budget. In order to facilitate our presentation, we first introduce the notation that we use, including indices, parameters, and variables. The mathematical formulation then follows.

A. Notation

We use capital letters to indicate parameters and sets. Lower-case letters refer to variables and indices. Dual variables are designated with greek lower-case letters. An asterisk on a variable (x^*) means that the variable is viewed as exogenous (fixed) by generation firms and the grid operator, but is actually endogenous (variable) to the market as a whole. (In the following presentation, "$x \perp y$" implies $xy = 0$.)

1) Sets and Indices:

$f, g \in F$	Generating firms.
$F^c \subset F$	Set of Cournot firms.
$h, h' \in H$	Generating unit.
$H(i,f) \subset H$	Set of f's generators at node i.

[2]Metzler et al. [13] consider only a single period electricity market with neither forward contracts, operating reserves, nor NO_x permits. Hobbs and Pang [31] extend those existence and uniqueness results to power markets with market power in input and pollution permit markets.

$H^{\text{OTC}}(i,f) \subset H$ Set of f's generators at node i whose emissions are included in the NO_x program.
$i, j \in I$ Nodes in network.
$t, t' \in T$ Period.

2) Parameters:

B_t Duration of period t in the load duration curve approximation [hours].
C_{fih} Marginal production cost of generator fih [$/MWh].
E_{fih} Emission rate of generator fih [lbs/MWh].
FOR_{fih} Forced outage rate of generator fih [dimensionless].
N_f Number of NO_x allowances assigned annually to firm f in the NO_x trading program [tons].
NPC_f Slope of NO_x conjectured price function for producer f [($/ton)/ton].
P^F_{fjt} Price for forward contracted power sale by firm f in node j in period t [$/MWh].
P^0_{jt}, Q^0_{jt} Vertical and horizontal intercepts of demand curve at node j in period t [$/MWh, MW].
PTDF_{ki} Power transfer distribution factor for a unit power injection at an arbitrary hub node and unit withdrawal at node i for transmission interface k [MW/MW][3]
R_{fih} Maximum operating reserve that can be provided by generator fih [MW].
RM Required operating reserve as a fraction of total load [dimensionless]
S^F_{fit} Forward contracted sales for firm f at node i in period t [MW].
T_k Upper thermal limit of interface k [MW].
X_{fih} Production capacity of generator fih [MW].
Z_{it} Electricity imported from outside the study region to node i in period t [MW].

3) Variables:

p^E_{jt} Price of power at node j in t period [$/MWh].
p^N_f Conjectured NO_x price by firm f [$/ton].
p^{N^*} Equilibrium price of NO_x permits [$/ton].
p^R_t Reserve market price in period t [$/MW].
r_{fiht} Operating reserve provided by generator fih in period t [MW].
s_{fjt} Total spot and forward power sales by firm f at node j in period t [MW].
w_{it} Transmission charge to move power from hub to node i [$/MWh] (endogenous to market but exogenous to producers)
x_{fiht} Power output of generator fih in period t [MW].
y_{it} Amount of power delivered from hub to node i by grid operator in period t [MW].
λ_{kt} Dual variable associated with upper limit of power flow through interface k in period t [$/MW].
ρ_{fiht} Dual variable associated with capacity constraints for generator fih in period t [$/MW].
θ_{ft} Dual variable for f's sale/output balance in period t [$/MW].
η_{fiht} Dual variable for plant fih's reserve upper bound in t [$/MW].

[3]The hub is the bus that, for the purpose of calculating PTDFs, is assumed to be the sink for injections at all other nodes. Because of the superposition principle in the linearized dc load flow model, the hub can be arbitrarily selected from any of the nodes in the network. That is, the value of $\text{PTDF}_{ki} - \text{PTDF}_{kj}$, which is the flow through interface k resulting from a unit withdrawal at i and unit injection at j, does not depend on the choice of hub.

In the remainder of this section, we first explicitly write out the optimization problem for each individual market participant (i.e., supplier, grid operator, consumer, and arbitrageur), including its objective function and constraints. Second, we derive the first-order Karush-Kuhn-Tucker (KKT) conditions associated with each variable. Third, collecting KKT conditions together with market clearing conditions will define a market equilibrium problem in form of a linear complementarity problem, which can be solved using complementarity solvers. The model presented is the full oligopolistic (Cournot and conjectured price response) model. We also note how some simplifications reduce that model to the case of perfect competition.

B. Maximization Models for Market Players

1) Consumers: Consumers are assumed to have no market power and their willingness-to-pay for electricity is implicitly represented by the inverse demand function

$$p^E_{jt} = P^0_{jt} - \left(P^0_{jt}/Q^0_{jt}\right)\left(\sum_f s_{fjt} + a_{jt}\right), \quad \forall j, t. \tag{1}$$

2) Producers: We assume that the bulk of power sales are in the form of bilateral contracts between producers and consumers, with the producer paying the system operator for transmission services necessary to deliver the power. In the case of oligopolistic competition, a few firms with substantial capacity are designated as strategic firms, exercising Cournot (quantity) strategies in the energy market. Under that strategy, those firms adjust their generation and sales as if they believe that rival firms will not react to such output changes. Mathematically, this is accomplished by inserting the inverse demand function (1) in the strategic firms' objective functions [first term in (2)]. In the case of price taking (competitive) companies, however, we use p^E_{jt} rather than (1) in the objective

$$\begin{aligned}
\text{MAX}_{x_{fiht}, s_{fjt}, r_{fiht}} & \sum_{j,t}\left(P^0_{jt} - \left(P^0_{jt}/Q^0_{jt}\right)\sum_g s_{gjt} - w_{jt}\right) \\
& \times B_t\left(s_{fjt} - S^F_{fjt}\right) \\
& + \sum_{j,t} B_t P^F_{fjt} S^F_{jit} + \sum_{i,h\in H(i,f),t} p^R_t r_{fiht} \\
& - \sum_t \sum_{i,h\in H(i,f)} B_t (C_{fih} - w_{it}) x_{fiht} \\
& - p^N_f\left(\sum_t \sum_{i,h\in H^{\text{OTC}}(i,f)} B_t E_{fih} x_{fiht} - N_f\right)
\end{aligned} \tag{2}$$

subject to

$$x_{fiht} + r_{fiht} \le X_{fih}(1 - \text{FOR}_{fih}), \quad \forall i, h \in H(i,f), t \quad (\rho_{fiht}) \tag{3}$$

$$r_{fiht} \le R_{fih}, \quad \forall i, h \in H(i,f), t \quad (\theta_{ft}) \tag{4}$$

$$\sum_j s_{fjt} = \sum_{i,h\in H(i,f)} x_{fiht}, \quad \forall t \quad (\eta_{fiht}) \tag{5}$$

$$p_f^N = p^{N*} + NPC_f \times \left(\sum_t \sum_{i,h \in H^{\mathrm{OTC}}(i,f)} B_t E_{fih} x_{fiht} - tot_f^{N*} \right)$$
$$\forall s_{fjt}, r_{fiht}, x_{fiht} \geq 0. \tag{6}$$

Each producer maximizes its profit by choosing its generation levels x_{fiht}, operating reserves r_{fiht} and sales s_{fjt} in each period. The term $P_{jt}^0 - (P_{jt}^0/Q_{jt}^0)\sum_g s_{gjt} - w_{jt}$ is the per megawatt hour (MWh) revenue of spot electricity sales to j's consumers, net of w_{jt}, the transmission charge paid to the grid operator to bring power to consumers from hub. This expression shows that the strategic generators recognize their ability to influence power prices through the inverse demand curve (1). Meanwhile, $\sum_{i,t} B_t P_{fit}^F S_{fit}^F$ is the locked-in revenue received by generators through forward contracts with customers; this is exogenous (or fixed) to the model, likewise for forward contract prices P_{fjt}^F. The term $\sum_{i,h \in H(i,f),t} p_t^R r_{fiht}$ comprises revenues from the reserve market. The $C_{fih} - w_{it}$ term is the per MWh cost of producing electricity from plant h, where $-w_{it}$ is the price charged by the transmission operator to bring generation to the hub. (That price term is negative, since the generator actually provides counterflow from the node to hub.) We assume that the direct cost of operating reserves is negligible. Finally, the term $\sum_t \sum_{i,h \in H^{\mathrm{OTC}}(i,f)} B_t E_{fih} x_{fiht} - N_f$ is the number of tradable permits purchased (positive) or sold (negative) over the compliance period. Multiplied by the allowance price, this then equals the net expense of $\mathrm{NO_x}$ allowances. (Notice the summation only applies to generators whose emissions come under the OTC cap.)

Turning to the constraints, in addition to nonnegativity restrictions, producers have three types of constraints. The variable in the parentheses to the right of each constraint is its dual variable. The first type includes capacity constraints. One such constraint limits the power output x_{fiht} plus operating reserve r_{fiht} to be no more than the generator's derated capacity. The other capacity constraint limits the amount of reserve from a generator. In the second type of constraint, energy generation and sales have to balance during each period. Finally, the conjectured $\mathrm{NO_x}$ price equation is a first order characterization of firm f's expectation concerning how the price of permits p_f^N will change from its equilibrium value p^{N*} if f changes the net amount of permits it buys or sells. This represents the producer's belief about how much market power it can exercise in that market. The slope of that function NPC_f may be an estimate of the actual market price response, but does not have to; this parameter can be varied systematically to explore how different expectations can affect equilibrium prices in the $\mathrm{NO_x}$ and, indirectly, energy markets. A positive value indicates that f believes it can affect the price of permits, while, a value of zero represents price taking behavior.[4] (In the implemented model, we will substitute that equation for p_f^N in the objective function, eliminating that variable and (6).)[5]

3) Power Arbitrageur: An arbitrageur is introduced in order to simulate POOL-type market, in which the transmission cost between two nodes equals the difference in spot prices [13]. The arbitrageur is assumed to have perfect knowledge of the equilibrium power prices, and it moves power from the low-price nodes to the high-price nodes to maximize its profit

$$\mathrm{MAX}_{a_{it}} \sum_{i,t} B_t \left(p_{it}^E - W_{it}\right) a_{it} \tag{7}$$

subject to

$$\sum_i B_t a_{it} = 0 \quad \forall t \quad \left(p_t^H\right). \tag{8}$$

As Metzler *et al.* [13] proved, the effect of an arbitrageur is similar to that of a pool operator: the result is that the cost of moving power from node i to $j (w_{jt} - w_{it})$ will equal the price difference between nodes $(p_{jt}^E - p_{it}^E)$.

4) Grid Operator: The operator allocates scarce transmission capacity among demands for transmission service

$$\mathrm{MAX}_{y_{it}} \sum_{i,t} B_t w_{it} y_{it} \tag{9}$$

subject to

$$\sum_i \mathrm{PTDF}_{ki} y_{it} \leq T_k, \quad \forall t \quad (\lambda_{kt}). \tag{10}$$

We use the dc approximation to derive power transfer distribution factors (PTDFs) to represent load flows in the network. The constraints associated with the grid operator are that the total flow has to be no more than the upper bound (T_k) for interface k based on thermal or other limits. (More complex constraints, such as nomograms, can be included if linearized.) Consistent with [3], we assume that the grid operator is a regulated entity that allocates transmission capacity efficiently among demands for transmission service, which is equivalent to a price-taking assumption for the operator [14]. Another way to view this model is that grid operates a market for interface capacity, similar to the flowgate market proposed by Chao and Peck [15]. Viewed in this manner, the KKT conditions for this problem ((g2), below) ensure market clearing: an interface's price λ_{kt} is positive only if it is constraining, and in that case, the price is set at the level at which demand for the interface [left side of (10)] just equals the supply [right side of (10)]. The KKT conditions also relate the price of point-to-point service w_{it} to the prices of the interfaces required to provide that service (condition (g1), below) [5].

5) Market Clearing and Consistency Conditions: These conditions are essential to calculating a market equilibrium. Not only does each commodity's clearing condition ensure balance of the physical system but it also implicitly generates a

[4]A similar approach can be used to model market power in the reserve market.

[5]Note that the model excludes unit commitment constraints such as minimum on- and off-times, ramp rate limits, and start-up costs. There are two reasons for this. One is that the model is a medium-term model (with a time horizon of months) rather than a short-term model; because unit commitment models require integer variables, it is not practical to solve them for an entire ozone season. In general, production costing models that are used for the length of time periods considered here omit such constraints for this reason. Second, use of integer variables means that existence of multiproducer equilibria cannot be proven, in part due to the well-known "duality gap." Nearly all power market oligopoly models omit integer variables for this reason.

price by forcing demand and supply to equilibriate. There are three sets of market clearing conditions, one for transmission services, one for emissions permits, and a third for the reserve market. The transmission condition requires that the demand for transmission service from each node equals the quantity supplied by the grid operator in each period. The tradable permit clearing condition is written as a complementary condition. If there are excess permits in the market, the price of market is zero; otherwise, it is positive. The third condition is analogous to (mc2), in which if there is more reserve capacity available in the market than required, the reserve market price p_t^R is zero; otherwise, it is positive. A fourth condition is also imposed, which is a consistency condition: it, together with (6), ensure that in equilibrium each firm's anticipated permit price p_f^N equals its equilibrium value p^{N*}

$$\sum_f s_{fit} + a_{it} - \sum_{f,h \in H(i,f)} x_{fiht} - Z_{it} = y_{it}, \quad \forall i,t \quad \text{(mc1)}$$

$$0 \le p^{N*} \perp \sum_f \left(\sum_t \sum_{i,h \in H^{\text{OTC}}(i,f)} B_t E_{fih} x_{fiht} - N_f \right) \le 0 \quad \text{(mc2)}$$

$$0 \le p_t^R \perp \sum_{f,i} s_{fit} \text{RM} - \sum_{f,i,h \in H(i,f)} r_{fiht} \le 0, \quad \forall t \quad \text{(mc3)}$$

$$\text{tot}_f^{N*} = \sum_t \sum_{i,h \in H^{\text{OTC}}(i,f)} B_t E_{fih} x_{fiht}, \quad \forall f. \quad \text{(mc4)}$$

C. Market Equilibrium Model

The next step in developing the model is to derive the KKT conditions for each of the market participant's optimization problems. Most of the derivations are straightforward, except $(f2^{\text{OTC}})$, below, which only applies to generating units coming under the OTC permit trading program. The market equilibrium problem is then defined as the collection of all KKT conditions for all the above problems together with the market clearing and consistency conditions (analogous to the derivations in [5] and [16]). The resulting complementarity problem can then be implemented in GAMS and solved with the complementarity solver PATH [17]. The complete market equilibrium problem is as follows.

a) Consumers: Demand function (1)

b) Producers:

For $s_{fjt}, \quad \forall f \in F, j, t:$

$$0 \le s_{fjt} \perp P_{jt}^0 - \left(P_{jt}^0 / Q_{jt}^0\right) \left(\sum_g s_{gjt} + a_{it} \right) - \left(P_{jt}^0 / Q_{jt}^0\right) \left(s_{fjt} - S_{fjt}^F\right) - w_{jt} - \theta_{ft} \le 0. \quad \text{(f1)}$$

[For price-takers, this simplifies to $0 \le s_{fjt} \perp p_{jt}^E - w_{jt} - \theta_{ft} \le 0$, with p_{jt}^E calculated from (1).]

For $x_{fiht}, \quad \forall f, i, h \notin H^{\text{OTC}}(i,f), t:$

$$0 \le x_{fiht} \perp -(C_{fih} - w_{it}) B_t - \rho_{fiht} + \theta_{ft} B_t \le 0 \quad \text{(f2)}$$

For $x_{fiht}, \quad \forall f, i, h \in H^{\text{OTC}}(i,f), \quad \forall t:$

$$\begin{aligned} 0 \le x_{fiht} \perp & -(C_{fih} - w_{it}) B_t \\ & - B_t E_{fih} \Bigg[p^{N*} + \text{NPC}_f \\ & \times \Bigg(\sum_{t'} \sum_{j,h' \in H^{\text{OTC}}(j,f)} 2 x_{fjh't'} B_{t'} E_{fjh'} \\ & - N_f - tot_f^{N*} \Bigg) \Bigg] \\ & - \rho_{fiht} + \theta_{ft} B_t \le 0 \quad (f2^{\text{OTC}}) \end{aligned}$$

For $\rho_{fiht}, \quad \forall f, i, h \in H(i,f), t:$

$$0 \le \rho_{fiht} \perp x_{fiht} + r_{fiht} - X_{fih}(1 - \text{FOR}_{fih}) \le 0 \quad \text{(f3)}$$

For $\theta_{ft}, \forall f, t:$

$$\sum_j s_{fjt} = \sum_{i,h \in H(i)} x_{fiht} \quad \text{(f4)}$$

For $r_{fiht}, \quad \forall f, i, h \in H(i,f), t:$

$$0 \le r_{fiht} \perp p_t^R - \rho_{fiht} - \eta_{fiht} \le 0 \quad \text{(f5)}$$

For $\eta_{fiht}, \quad \forall f, i, h \in H(i,f), t:$

$$0 \le \eta_{fiht} \perp r_{fiht} - R_{fiht} \le 0. \quad \text{(f6)}$$

c) Arbitrageur:

For $a_{it}, \quad \forall i, t:$

$$p_{it}^E - W_{it} - p_t^H = 0 \quad \text{(a1)}$$

For $p_t^H, \quad \forall t:$

$$\sum_i B_t a_{it} = 0 \quad \text{(a2)}$$

d) Grid Operator:

For $y_{it}, \quad \forall i, t:$

$$w_{it} B_t - \sum_k \text{PTDF}_{ki} \lambda_{kt} = 0 \quad \text{(g1)}$$

For $\lambda_{kt}, \quad \forall k, t:$

$$0 \le \lambda_{kt} \perp \sum_i \text{PTDF}_{ki} y_{it} - T_k \le 0 \quad \text{(g2)}$$

Market Clearing Conditions: (mc1)–(mc4)

III. Case Study Background

A. PJM Market

The PJM began operating as an ISO in 1998. It runs a day-ahead, hourly-ahead energy, and operating (spinning) reserve market. Its hourly load in 2000 ranged from 20 000 to 49 000 MW. Nuclear and coal plants serve the baseload, accounting for 57.9% of total generation capacity. Meanwhile, the capacity shares of oil, gas, and hydro plants are 20.8%, 18%, and 3.3%, respectively. In our model, the PJM system is spatially represented by 14 aggregated nodes (each representing one Power Control Area or a portion thereof) and 18 transmission lines (Fig. 1). The highest average load among the nodes is 5300 MW for Public Service Electric and Gas

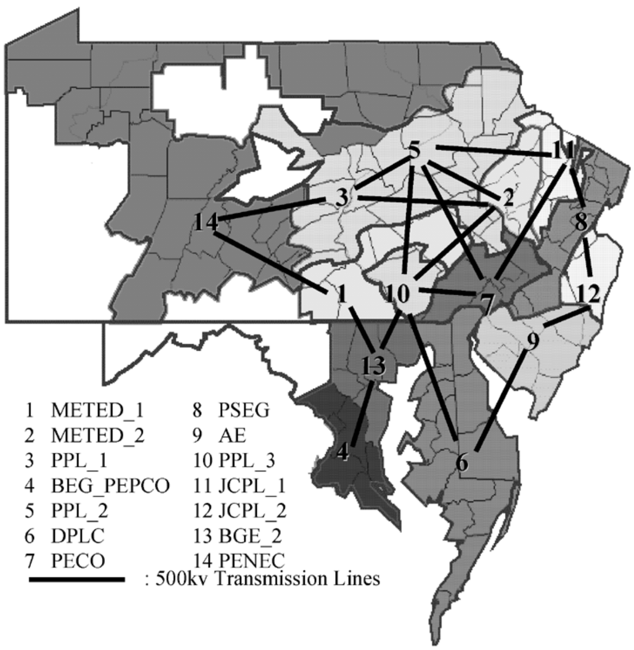

Fig. 1. Schematic of linearized dc network for PJM.

Co. (PSEG) and the lowest is 1310 MW for Atlantic Electric Co. (AE). During the ozone season of 2000, PJM exported respectively an average of 600 and 100 MW to the New York ISO (NYISO) and Virginia Electric Power (VEP), and imported 1200 and 315 MW from Allegheny Power System (APS) and First Energy (FE), respectively. For simplicity, we treat these external flows as fixed in our model, although price responsive imports/exports could also be modeled [18]. The market is moderately concentrated, with an average hourly HHI (Hirschman-Herfindahl Index) of 1 544 [19]. There are 6 larger generating companies, owning between 6% and 19% apiece of the generating capacity. Although the PJM market monitor reports that prices have generally been near competitive levels [19], there has apparently been some market power exercised in the installed capacity market. Furthermore, other studies indicate that market concentration is high enough to present a risk of market power being exercised [20], [21].

B. OTC NO_x Budget Program

The OTC NO_x budget program is a cap-and-trade program that came into effect in 1999. Its goal is to reduce summer NO_x emissions region-wide to help northeastern states attain the National Ambient Air Quality Standard (NAAQS) for ground level ozone. The effective period is from May 1 to September 30 of every year. The program has evolved over time to encompass a larger geographic scope, from an initial nine states in 1999 to nineteen states in 2004 [22]. The tradable permits were initially allocated to affected facilities owners according to their historical seasonal heat inputs multiplied by a target NO_x emission rate. The flexibility of the program allows owners of permits to sell excess permits or bank them for future use. The program applies to electric generating units of a rated capacity of 25 MW or greater along with larger industrial process boilers and refineries. There are a total of 470 individual sources affiliated with 112 distinct organizations in the program in 1999. Ninety percent of NO_x emissions covered in program are from power generators. In our PJM database, more than 70% of generator summer capacity comes under the NO_x budget program including 422 generators. We omit nonpower sources from our analysis because of their small size, and because our focus is on the power industry.

The mandated NO_x reductions take effect in two phases. The first phase began in May 1, 1999 when the program required affected facilities to cut total emission to 219 000 tons in 1999, less than half of the 1990 baseline emission of 490 000. The emissions cap is to be cut further to 143 000 tons in 2003 for the second phase, a reduction of 70%. Since our purpose is to illustrate the use of this methodology, we will model just the use and sales of allowances within PJM, even though the NO_x budget program covers a region larger than PJM. Thus, our analysis may overstate the extent to which market power can be exercised in the NO_x market because the model disregards trading outside of PJM. This will, in effect, overstate the concentration in that market, but will serve the purpose of illustrating how one can model the interactions between electricity and permits markets in the presence of market power.

C. Data Sources

1) Ownership: Ownership and location data are crucial to our analysis since they determine the potential to exercise market power. The primary source of this data is EIA Form 860 [23]. For units not in EIA 860, an internet search or personal contact was used to confirm ownership. To ensure an appropriate representation of the potential of market power under the current ownership, we assume that operational decisions (generation and sale) are controlled by the parent company, replacing any subsidiaries with the corresponding parent company. For the 29 units jointly owned by more than one incumbent company, we treat each as a set of multiple units by splitting capacity in proportion to ownership percentage. Other assumptions, such as assigning control to the owner with majority ownership, could instead be applied to study market power in the presence of partial ownership [24].

There are nine companies in our PJM model. For our purpose, we designate the six largest companies as strategic firms with respective capacity shares of 18.9%, 18.4%, 14.0%, 10.9%, 8.7%, and 6.1%. The reason for modeling all six as strategic is the possibility that even a small one can exercise market power if its generators are located in a transmission-constrained area. With others companies having a capacity share of only 0.6% to 3.4%, we believe that the likelihood for them to exercise market power is much less. Therefore, we designate them as price takers (competitive).

2) Loads: The simulation period is the ozone season in year 2000, comprising 3672 h. The load is represented by five blocks: a peak-load block with a width of 52 h, and four nonpeak blocks having 905 h each. Hourly load data for each individual Power Control Area (PCA) or node are obtained from the PJM website, as are boundary conditions (net imports). We assume a demand elasticity of 0.2 when constructing inverse demand curves. This elasticity reflects consumer reactions not only through real-time pricing programs, but also some medium-term response due to electric rate changes and utilization of distributed generation.

3) NO_x Tradable Permits Data: We rely on EPA annual compliance reports for tradable permit data [25]. A total of 131 440 permits were available at the end of 2000 for affected facilities in Maryland, Pennsylvania, New Jersey, and Delaware. There were 109 227 permits allocated in 2000 by the NO_x budget program, and 22 163 permits were carried over (banked) from previous years. Only 92 107 permits are assigned to power plants; the remaining permits, which are owned by other industrial sources, are left out of our analysis. Consistent with empirical observation of generator behavior in PJM, we assume only 80% of available permits are used for compliance purpose, and the remaining 20% are banked for years after 2000.

4) Generator Characteristics and Network Data: A total of 731 generating units are included in the market model. We represent each unit's marginal production cost as the sum of fuel cost, SO_2 permit costs, and nonfuel variable operation and maintenance expenses. The required data, such as heat rate, capacity, emission rate and other information, are drawn from multiple sources including EIA databases, the USEPA Integrated Planning Model and Generation Resource Integrated Database [26], and the PowerWorld website [27]. For units without complete data, we estimates their values taking into account prime mover, fuel type, capacity, vintage year and other related factors. Capacity is derated by its forced outage rate (FOR) to account for unpredicted plant outages. The value of FOR depends on prime mover and unit size, and is drawn from NERC data [28]. Finally, the maximum capability to provide operating reserves depends on the type of generator, and is defined by a percentage of unit capacity (J. Bowring, PJM, personal communication). We assume a total reserve requirement of 7.5% of load; there are no locational restrictions.

In our database, the average fossil-fueled plant NO_x emission rate is 4.5 lbs/MWh, ranging from 1 to 25 lbs/MWh. When facing a NO_x emission constraint, the only strategy for firms in the short run is to rely on NO_x emissions dispatch, in which more expensive but cleaner facilities are operated more than otherwise [29]. In contrast, many options that involve capital investment in low NO_x burners or post-combustion control technologies such as non-selective catalytic reduction (NSCR) are available in the long run. A model attempting to simulate those options requires additional variables for these investments and multiyear time horizons.

Network data, including transmission thermal capacities and reactances required for deriving PTDFs, were obtained from the PowerWorld website [27].

5) Vertical Integration and Forward Contracts: The PJM market was highly vertically integrated during 1999–2000. According to Mansur [30], 53% to 59% of power in PJM is self-supplied by vertically integrated utilities; about 30% through short- or long-term bilateral contracts, and only 10% to 15% of power transactions are through the spot market. The remaining 1% to 2% is imported. Because of the lack of publicly available data, we estimate the forward contracting position of each generating firm as follows. We assume there are four vertically integrated load-serving entities (LSE): Constellation, PECO, PPL, and PSEG. The remainder entities are independent suppliers. We define the native load of those vertical integrated LSEs as the corresponding nodal load net of customer load served by alternative suppliers. For independent power suppliers, their contracted load is the load of LSEs that sold their generation assets to the suppliers (net of supply from alternative suppliers). For each merchant supplier who built new plants, we assume that it contracts 90% of its capacity to the nodes at which its plants are located. Additional adjustments are applied such that market structure is consistent with the fact that PECO and PPL are the major two LSEs having a long position in the spot market [30]. As a result of these assumptions, 86.9 TWh of energy is assumed to be forward contracted, 75% of the total load under perfect competition.

TABLE I
SPOT POWER AND RESERVE PRICES [$/MWh] UNDER PERFECT COMPETITION

Node\Period	1	2	3	4	5	Mean[a]
METED_1	71.6	48.2	24.4	19.6	17.1	30.0
METED_2	66.0	48.2	23.7	19.4	17.1	29.6
PPL_1	61.6	48.1	23.1	19.3	17.1	29.3
BGE_PEPCO	87.0	48.3	24.7	19.7	17.1	30.9
PPL_2	57.1	48.1	22.5	19.2	17.1	29.0
DPLC	74.9	48.5	27.5	20.3	17.1	31.4
PECO	90.0	48.1	22.5	19.2	17.1	30.1
PSEG	75.1	49.1	35.9	22.2	17.1	34.5
AE	74.9	48.5	28.1	20.4	17.1	31.9
PPL_3	74.9	48.3	24.8	19.7	17.1	30.2
JCPL_1	75.1	48.0	20.8	18.8	17.1	26.8
JCPL_2	75.1	49.0	35.2	22.1	17.1	34.9
BGE_2	74.0	48.3	24.7	19.7	17.1	32.2
PENEC	65.1	48.2	23.6	19.4	17.1	30.0
Mean[a]	77.0	48.4	26.7	20.1	17.1	31.2
Reserve	24.2	0.0	0.0	0.0	0.0	0.5

[a]:Sales-weighted average

TABLE II
SPOT POWER AND RESERVE PRICES [$/MWh] UNDER OLIGOPOLY
(FORWARD CONTRACTING CASE)

Node\Period	1	2	3	4	5	Mean[a]
METED_1	76.0	50.0	28.9	21.1	18.2	32.4
METED_2	73.3	49.6	28.4	21.0	18.2	32.1
PPL_1	71.1	49.3	28.1	21.0	18.2	31.9
BGE_PEPCO	87.0	50.2	29.1	21.1	18.2	33.2
PPL_2	68.9	49.0	27.7	21.0	18.2	31.6
DPLC	77.7	50.3	30.8	21.1	18.2	33.3
PECO	85.1	51.4	27.7	21.0	18.2	33.1
PSEG	77.7	50.3	35.9	21.2	18.2	35.0
AE	77.7	50.3	31.1	21.1	18.2	33.7
PPL_3	77.6	50.3	29.1	21.1	18.2	32.5
JCPL_1	77.7	50.3	26.7	21.0	18.2	29.5
JCPL_2	77.7	50.3	35.5	21.1	18.2	35.4
BGE_2	77.2	50.2	29.1	21.1	18.2	34.7
PENEC	72.8	49.6	28.3	21.0	18.2	32.5
Mean[a]	79.3	50.3	30.3	21.1	18.2	33.3
Reserve	23.9	0.0	0.0	0.0	0.0	0.5

[a]:Sales-weighted average

IV. RESULTS OF ILLUSTRATIVE APPLICATION

A. Comparison of Actual and Simulated Prices

Tables I and II summarize the model's price equilibria under both perfect and oligopoly competition. Prices are reported for each network node in each period. We first compare our results with PJM reported load-weighted locational marginal prices (LMPs) (see Fig. 2), focusing on price variations across

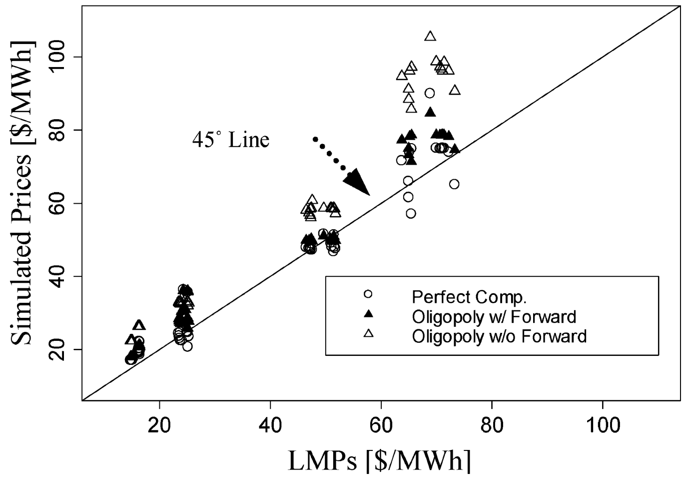

Fig. 2. Comparisons of Average 2000 Ozone Season LMPs and Simulated Prices (source for LMPs: www.pjm.com).

nodes and time periods. Since our network is based on just the 500-kV PJM grid, the comparison is limited to the aggregated LMPs associated with 500-kV buses.

The corresponding actual LMPs we selected to compare with our simulated prices are the 95th percentile price, average over 95th to 75th, average over 75th to 50th, average over 50th to 25th percentile, and the 25th percentile price for the first to fifth periods, respectively. These percentages correspond to the five load blocks of the model. The individual points in Fig. 2 represent a simulated and actual price pair for one period for one control area in the network. Points lying on the 45° line in the figure would indicate a perfect match. The figure shows no substantial prices differentials between perfect and oligopoly competition with forward contracts, except during the highest price period. Both simulated prices (perfect and oligopoly competition with forward contracts) are a good approximation of actual PJM LMPs, except that higher power prices for oligopoly competition are predicted in peak periods. In contrast, if there is no forward contracting, the average peak Cournot power price (96.4 $/MWh) is 25% and 22% higher, respectively, than perfect competition and oligopoly with forward contracts.[6] This result is consistent with theory which says that forward contracts diminish the short run incentive for generator to withhold output, resulting in lower markups in Cournot equilibria.[7] The sale-weighted PJM price is 68.3 and 77.0 $/MWh for actual LMPs and the competitive model, respectively during the peak. Except for an over-prediction of PPL_3 prices, the model reports that the region's highest prices tend to occur in DPLC, PECO, PSEG, AE, JCPL_1, and JCPL_2, consistent with reported LMPs. Nevertheless, with a respective standard deviation of 8.8 versus 3.4 $/MWh for the competitive model and LMPs during the peak period, respectively, our predictions tend to have a larger price variation (and therefore congestion) across nodes. Additionally, the competitive model's NO_x permit price of 1268 [$/ton] is within the range of permit prices observed in 2000 [9].

TABLE III
OTHER PERFECT COMPETITION SOLUTION RESULTS

Price of NO_x permits [$/ton]				1,268
Consumer surplus [M$]				12,241
Importer's revenue [M$]				135
Grid operator revenue [M$]				59
Social Welfare[a] [M$]				12,250
Firm	Profit [M$][a]	Permit Trade[b] [tons]	Total Sales [10^6 MWh]	Variable Gen. Cost [M$]
Conectiv	-73.7	-1,445.6	2.0	37.5
Constellation[c]	-93.0	1,665.6	16.7	193.0
Mirant[c]	-160.5	0.0	10.3	194.2
PECO[c]	437.4	-9,615.5	29.0	106.6
PPL[c]	14.8	11,396.9	17.6	150.2
PSEG[c]	-60.3	2,880.7	18.2	124.3
Reliant[c]	-106.7	2,462.6	6.2	98.5
Allegheny	23.4	137.5	1.1	8.1
Others	-166.9	-7,482.2	17.6	323.9
Total	-185.7	0.0	118.7	1,236.2

[a] Excludes fixed revenue from forward contracts
[b] Positive means a net purchase of NO_x permits and negative means a net sale
[c] Indicates firm exercises conjectured NO_x permit price strategy in emissions market and Cournot strategy in spot markets in oligopolistic competition

B. Comparison of Competitive and Oligopoly Solutions

Now we turn to a comparison of the oligopolistic market solutions (in which the six largest firms exercise a Cournot strategy in electricity market and a conjectured pricing strategy in permit market) with the competitive solution. The focus is on the oligopoly case with forward contracts. Here, we apply a NO_x conjectured price slope (NCP_f) of 0.1 [($/ton)/ton] to all Cournot firms and one of zero to price-taking firms. That is, the larger firms are assumed to expect that the price of permits would increase (decrease) $0.1/ton for every additional ton of allowances they purchase from (sell to) the market, while smaller firms are price takers.[8] Of course, the beliefs of firms cannot be observed, so we take this as a base case value to be subjected to sensitivity analysis.

Tables I–IV summarize the results of the perfect competition and oligopoly solutions (with forward contracts). One caveat of our calculation is that the listed profit excludes revenues from forward contracts, which are fixed. However, this simplification will not affect our social welfare analysis since fixed revenues cancel out when comparing solutions. The solutions show that total consumption decreases by 1.5% under the oligopoly (forward-contracted) scenario and prices of electricity go up accordingly among most nodes. Measured relative to competitive prices, Tables I and II show that the overall average power price in the oligopoly scenario increases by 2.1 $/MWh (or 6.7%) from 31.2 to 33.3 $/MWh. The average increase is largest in the

[6]The average power price (across nodes and periods) for oligopoly competition without forward contracts is 39.5 $/MWh. The most substantial impact in the peak period occurs in PPL_2 in which the power price goes up by 23.3 $/MWh (or 41%), and the least impact is in BGE_PEPCO (an increase of 8.2 $/MWh, or 9.4%). However, the peak reserve price drops to 13.7 $/MWh, reflecting the fact that less operating reserve is required, given that total consumption decreases to 111.7 TWh.

[7]Mansur [30] argues that the vertical integration of generators with LSEs in PJM results in lower Cournot prices than the case in which there is no vertical integration. One would expect in the longer term, as forward contracts are renewed, the market power could be reflected in the terms under which those contracts are signed.

[8]This value is consistent with the actual response of the market in the competitive case (Table III). For example, we simulated a decrease of 900 tons in the markets, and the result was a 84 $/ton increase in the NO_x permit price.

TABLE IV
OTHER OLIGOPOLY SOLUTION RESULTS (FORWARD CONTRACTING CASE)

Price of NO_x permits [\$/ton]				458
Consumer surplus [M\$]				12,173
Importer's revenue [M\$]				147
Grid operator revenue [M\$]				35
Social Welfare[a] [M\$]				12,188
Firm	Profit [M\$][a]	Permit Trade[a] [tons]	Total Sales [10^6MWh]	Variable Gen. Cost [M\$]
Conectiv	-78.7	-624.6	2.3	45.7
Constellation[c]	-87.9	1,665.6	15.7	164.9
Mirant[c]	-160.7	0.0	10.8	203.3
PECO[c]	438.7	-12,947.2	26.2	65.2
PPL[c]	33.9	9,016.4	16.5	130.5
PSEG[c]	-66.6	2,824.1	18.2	123.5
Reliant[c]	-102.1	4,699.2	7.3	118.5
Allegheny	26.2	176.5	1.1	8.5
Others	-166.6	-4,810.1	18.7	348.8
Total	-163.8	0.0	116.9	1,209.0

Notes: same as Table III

third period (3.6 \$/MWh, 13.5% over the competitive price in that period), and least in the fourth period (1.0 \$/MWh, 4.8%). Interestingly, some nodes, i.e., PECO, PSEG, and JCPL_2, experience a lower price under oligopoly competition during some periods. This may be in part because higher energy consumption under perfect competition scenario results in more network congestion, a phenomenon found in other oligopoly models.

Finally, the operating reserve price is 24.2 and 23.9 \$/MWh for perfect and oligopoly (forward contracted) competition in the peak period, respectively, and zero at other times. This is the consequence of two counteracting forces. One the one hand, higher energy consumption under perfect competition indicates a larger reserve requirement, which can imply higher reserve prices. On the other hand, the reserve prices also reflect the opportunity cost associated with diverting capacity from the energy market (which, for the competitive fringe, is lower under perfect competition). In our simulation, the effect of the former marginally offsets the latter, yielding slightly higher reserve prices under perfect competition. However, these estimates are below the average reserve price reported by PJM during the 2000 ozone season.

Furthermore, individual output levels shrink for four of the six Cournot firms (forward contracted case) as a result of their recognizing the opportunity of gaining profits in electricity market by restraining their output. On the other hand, the output of the competitive fringe (the smallest three firms) expands because the small firms cannot significantly affect price by withholding output. They instead sell more in response to the higher Cournot prices, until their marginal cost equals or exceeds the nodal electricity price. The solutions indicate that two of the Cournot suppliers suffer decreased profit compared to competition while only two of competitive fringe profit from expanding their output in the electricity market. Such results are unfamiliar ones of Cournot models, in which profit should be higher for all suppliers under oligopoly competition. In general, a supplier's profit can be apportioned into four terms: electricity sales, production cost, ancillary service, and permits sales. The effect of output adjustments under oligopoly competition is complicated by the interaction of electricity, ancillary service, and emission allowance markets. For instance, while shrinking output, PPL loses 11.5 M\$ in electricity revenues; but that loss is more than made up for by production cost savings (20.3 M\$) and additional revenues associated with permit sales (10.3 M\$). The result is a net gain of 19.2 M\$. These interactions are discussed further in the next subsection.

Turning to the grid owner, smaller sales also mean less congestion, so grid operator revenue decreases by about half in the oligopoly (forward contracted) run. Consumer surplus also shrinks because of the price increases. Total social welfare (the sum of all surpluses, and an indicator of overall economic efficiency) declines by 62.0 M\$ for the five month period. This decline results from both allocative inefficiencies (consumers are not buying power whose worth (price) exceeds the marginal cost of production) and productive inefficiencies (the power sold is not produced at least cost). The loss of production efficiency can be obtained by solving a separate model that minimizes the cost of meeting the oligopoly solution demands; the resulting cost (1 189 M\$) is 20 M\$ less than Table IV, showing that oligopoly increases costs. This happens because expensive fringe production replaces cheaper oligopoly output that is withheld in the Cournot solution.

Although the allocative and productive efficiency impacts of market power are significant, they are much smaller than if there was no forward contracting or vertical integration to mitigate market power in the spot market.[9]

C. Energy-NO_x Market Interaction

A unique feature of our model is its endogenous treatment of the interaction of the pollution permit and energy markets. The model provides details on NO_x permit prices, trades, each firm's net position in the permit market, and total emissions. Below we discuss some ways in which market power in the two markets can interact.

Our PJM model shows that the permit price would drop from 1268 to 458 \$/ton as a result of firms exercising market power and restraining their energy output and, thus, their need for permits (compare Tables III and IV). For instance, PPL decreases its total sales by 1.1 TWh under oligopoly competition and accordingly acquires 2381 tons fewer permits.

Nevertheless, it is possible that a generator who is a net seller of permits could become a net buyer if the permit price drops so low that it is profitable for that generator to expand its output and acquire more permits than it possesses. For instance, in the *no forward contract* oligopoly solution, the permit price will drop all the way to zero because of the restriction of output by Cournot suppliers. In this solution, Conectiv, and PSEG switch positions from net sellers to buyers or vice versa in the tradable permit market. Conectiv, which is modeled as a price taker in our model, takes advantage of the energy price increases to expand its output. The amount of NO_x permits it consumes in the oligopoly simulation thereby expands and results in a switch in

[9]The loss of consumers' surplus in the Cournot (no forward contract) case compared to the forward-contracted Cournot case is −3 609 M\$. This indicates a substantial income transfer from consumers to producers, and that the existence of forward contracts mitigates the market power in the spot market. The total social welfare under the no forward-contracted scenario declines by 178 M\$. Meanwhile, the Cournot case without forward contracts has a productive efficiency loss of 84.0 M\$ compared to the forward contracted case.

its position in the NO_x market. The opposite argument applies to PSEG; it strategically contracts output, shrinking its emissions, and converts into a net seller of permits. On the other hand, company Reliant incrementally increases its acquisition of NO_x permits under oligopolistic competition. An explanation is that it takes advantage of the lower NO_x permit price, and some of its high emissions generators, which were otherwise shut down in the perfect competition scenario (because of their high NO_x permit costs), are dispatched in oligopoly competition case. The average NO_x emission rate for Reliant went up slightly under this oligopoly solution (from 3.70 lbs/MWh under competition to 3.73 lbs/MWh under oligopoly). In contrast, all competitive firms would utilize more permits because they expand production. Nevertheless, a total of 2306 tons of permits are left unused in the market in the oligopoly solution (no forward contracts), and the NO_x price crashed to zero.

In general, the impact of including a NO_x price conjecture in our analysis can be investigated by comparing Cournot solutions with- and without the conjecture assumption (the latter solution not shown here). We especially look at PECO (the only Cournot firm that is long in permits under perfect competition) and PPL (the largest Cournot firm short of permits in perfect competition). Recognizing its possible ability to increase the price of the permits it sells, PECO restricts its sale of permits from 13 570 tons in the pure Cournot scenario (forward contracts, no NO_x price conjecture) down to 12 947 tons in the conjectured case, a difference of 4.6%. Meanwhile, on the net consuming side of the market, PPL demanded 1 142 fewer tons of permits with a positive NCP_f (10 158 without the conjecture versus 9016 tons with the conjecture) in an attempt to drive down the NO_x permit price. The net impact is a drop in the permit price from 717 ($\mathrm{NCP}_f = 0$) to 458 \$/ton ($\mathrm{NCP}_f = 0.1$ for Cournot suppliers, with forward contracts). Certainly, the resulting NO_x permit price is a function of both (a) the share of each firm's generation capacity in the electricity market and (b) the direction (short or long) and magnitude of its net position in the permit market.

As noted in the previous section, only four of six Cournot firms changed their energy outputs under oligopoly in ways consistent with a simple Cournot model: larger Cournot producers should restrict output, while competitive producers expand production. In general, more complex (and counter-intuitive) changes can occur because of the interaction of markets for energy and pollution permits. For instance, it is possible for the profit of a Cournot firm to be *less* under the oligopoly competition if there are large changes in NO_x permit prices. In particular, when a firm is a net seller in the permit market in the competitive solution, it could suffer a large decrease in permit revenues in the oligopoly solution, where the permit price is lower. That price has decreased because of a net decrease in total energy sales by 1.8 TWh, resulting from the output adjustment by fringe (+1.5 TWh) and Cournot suppliers (−3.3 TWh) (forward contracts case); as a result, the demand for permits is decreased. Consequently, the price of permits could fall so far that a permit seller's loss of revenue in the permit market can outweigh the additional revenue obtained from exercising market power in the electricity market.

Another counter-intuitive possibility is that a Cournot firm profits by expanding output in the Cournot solution, if it owns dirty plants and the decreased price of allowances lowers costs so much that it is worthwhile to expand output from those plants. This is likely to be one reason why Reliant expanded its output, because it is a net buyer of allowances.

Another possible strategy that could arise in linked energy-permit markets, which has been alleged to occur in California [9], is deliberate over-consumption of permits to push up the price of permits (and thus the costs of rival generators). This cost-squeezing strategy can be investigated in our model by assigning a large value of the conjectured price response NCP_f to one or more of the firms that has a "long" position in permits. Those generators would then be strongly motivated to restrict their sales of permits, increasing price. In several oligopoly simulations (not shown), we have altered NCP_f together with the total supply of permits. We have found that if we maintain the forward contracts assumption, and if a relatively high price response (for instance, an $\mathrm{NCP}_{\mathrm{PECO}}$ of 1.5 [(\$/ton)/ton]) is combined with a tight permits supply (e.g., a reduction of 20% so the permit price p^{N*} is also high), then a strategy of restricting sales of permits and increasing their price can indeed be profitable (with forward contracts).

For instance, under the NO_x assumptions just mentioned, PECO would have found it worthwhile to increase its energy output by 7.3% (1.9 TWh) while restricting its sales of permits by 45% (from 11 120 to 6061 tons) relative to an oligopoly solution with the same number of available permits but lower values of NCP_f. This strategy increases PECOs profit by 2.7 M\$. This profit increase occurs because the price of permits increases from 3116 \$/ton (if there are 20% fewer permits but assuming $\mathrm{NCP}_f = 0.1$, as in Tables II and IV) to 3 613 \$/ton (also with 20% fewer permits, but with $\mathrm{NCP}_{\mathrm{PECO}} = 1.5$); such a price increase inflates marginal generation costs for other firms, motivating them to restrict their output by an additional 1.8 TWh. Thus, by this strategy, PECO increases its energy sales at the expense of other producers. PECO's revenue from NO_x permit sales actually decreased but this is more than made up by its increases sales and profits in the electricity market.[10]

However, the cost-squeezing strategy is not found to be profitable in our PJM solutions under a normal supply of permits, as the NO_x price is too low. In contrast, in California in the fall of 2000, NO_x prices were one to two orders of magnitude higher than have been experienced in PJM. As a result, NO_x emissions costs could amount to several tens of dollars per MWh, rendering such a strategy potentially profitable.

V. Conclusion

A process-based market equilibrium model has been formulated as a complementarity problem, and has been demonstrated to be a potentially useful tool for studying the exercise of market power in interacting energy, transmission, and pollution emission permits markets. The complementarity approach to modeling transmission-constrained power markets has been extended by creating an intertemporal constraint over

[10]The revenue loss in the permit market is: $3613\ [\$/\mathrm{ton}] * 6\ 061\ [\mathrm{tons}] - 3\ 116 [\$/\mathrm{ton}] * 11\ 120\ [\mathrm{tons}] = 12.8$ M\$.

an entire ozone season and allowing permit trading to take place between firms. In our model, generators can exercise market power in the energy market (Cournot game) and in the emissions permits market (using the notion of a conjectured price response function [5]). The exact numerical conclusions depend, of course, on assumptions such as price elasticity and the type of competition (e.g., supply function equilibria [5] will yield greater generation and therefore, in all likelihood, greater NO_x prices than Cournot equilibria). However, our analysis illustrates some qualitative results that can result from strategic behavior generators in multiple markets.

Our illustrative application to the PJM market shows that strategic behavior would have a substantial impact on NO_x permit prices, and that the price of permits can influence electricity generation. Furthermore, sensitivity analyzes show that when allowance supplies are tight, it is sometimes possible for a generator that is long in allowances profitably restrict its sale of allowances. This raises the price of allowances and, thus, marginal generation costs for buyers of allowances; this motivates those generators to sell less power, allowing the long generator to sell more. The detail that the model includes on generation, the network, and emissions enables a user to address a variety of "what-if" type of policy questions, such as:

- "What would the NO_x permit price be if the cap is imposed throughout an entire year?"
- "What would be the profitability to a large generator of a strategy designed to manipulate the price of allowances in order to increase production costs for rival firms?"
- "What would be the permit price if some restrictions are imposed on inter-regional permit trading?"
- "What if market power could be exercised in the operating reserves market?"

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