A MIXED COMPLEMENTARITY MODEL OF HYDROTHERMAL ELECTRICITY COMPETITION IN THE WESTERN UNITED STATES

JAMES BUSHNELL

University of California Energy Institute, 2539 Channing Way, Berkeley California 94720, jimb@ieor.berkeley.edu

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This paper presents a modeling framework for analyzing competition between multiple firms that each possess a mixture of hydroelectric and thermal generation resources. Based upon the concept of a Cournot oligopoly with a competitive fringe, the model characterizes the Cournot equilibrium conditions of a multiperiod hydrothermal scheduling problem. Using data from the western United States electricity market, this framework is implemented as a mixed linear complementarity model. The results show that some firms may find it profitable to allocate considerably more hydro production to off-peak periods then they would under perfect competition. This strategy is a marked contrast to the optimal hydroschedules that would arise if no firms were acting strategically. These results highlight the need to explicitly consider profit-maximizing behavior when examining the impact of regulatory and environmental policies on electricity market outcomes.

1. INTRODUCTION

One of the key characteristics that differentiates markets for electricity from those for most other commodities is the lack of a means to economically store the product. At high demand levels many producers are operating at their maximum output, and the number of potential suppliers for any additional units of demand is therefore reduced because there is no inventory of power to draw upon. The lack of storage also exacerbates the potential impact of transmission constraints between regions. The geographic scope of markets therefore can change seasonally and even hourly. Markets like California, that appear to be competitive during off-peak months or hours, still show evidence of significant market power during high demand periods (see Borenstein et al. 2000b). The lack of storage also creates the incentives for rather complex strategic manipulation of transmission constraints (see Cardell et al. 1997 and Borenstein et al. 2000a).

Hydroelectric resources provide the primary, and most significant, exception to the conventional assumption that electricity cannot be stored. Utilities that control hydro resources can, subject to some constraints, "move" energy between periods by adjusting the rates of releases from their reservoirs. This form of storage through deferred production could be accomplished by even conventional generation sources willing to inventory fuel. In practice, however, only hydro resources share the characteristics of large instantaneous output capacities and limited energy sources. Unlike other large generation facilities, such as coal and nuclear plants, most hydro facilities were never intended to operate at full capacity most of the time. The optimal operation of hydro facilities, therefore, usually involves allocating the limited energy available to the hours in which it has the most value. There are interesting parallels to the results of this paper in other more general scheduling problems, such as the timing of maintenance on thermal plants. Just as a strategic hydro firm may find it profitable to reduce peak output in favor of additional off-peak output, a strategic thermal firm may prefer to perform maintenance during peak hours, where it may significantly increase prices for other plants that are still operating.

Even in a regulated environment, hydro facilities have filled an important role in the operation of electric systems. The ability to concentrate hydro generation on high demand hours allows utilities to "shave" the peaks off of fluctuating demand, thereby reducing the need for investment in other forms of capacity. The relatively high level of operating flexibility provided by hydro plants also allows utilities to inexpensively follow demand fluctuations in real time and to quickly respond to random supply or demand shocks.

The role of hydroelectric generation in a deregulated market is even more significant. One source of the disruptions experienced in the power markets of the western U.S. during 2000 and 2001 has been the been the low levels of rainfall in the Pacific Northwest. In the hands of non-strategic firms, the storage capability of hydro power can, to some extent, allow those firms to arbitrage between the higher-priced peak and lower-priced off-peak markets that might otherwise be distinct due to transmission and other capacity constraints. If enough competitive hydro capacity is available, there would no longer be a distinction between peak and off-peak markets. Conversely, in the hands of a strategic firm, the ability to shift generation across time can produce a further separation of these geographically and temporally distinct markets. This separation can allow some firms to profitably exploit their dominant positions during peak hours while their competitors are capacity constrained.

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Hydro facilities may also present some significant disadvantages to strategic firms relative to more conventional sources of power production. Large hydro facilities play a prominent role not just in the operation of electricity systems, but also in flood control, irrigation, municipal water supply, and transportation. The construction and operation of hydro facilities also produce serious environmental consequences that are becoming increasingly controversial. These considerations must all be simultaneously balanced and often constrain the use of hydro facilities from their otherwise optimal application to electric power production. The confluence of so many interests in the arena of water policy also raises the visibility of hydro operations, making it more difficult for operators to withhold energy production through such transparent means as the excessive "spilling" of water.

In this paper, I attempt to quantify the extent of these advantages and constraints in the context of the electricity market in the western U.S. This market possesses many features that make it an interesting test case for such an analysis. First, major portions of this market have moved toward unregulated market-based pricing in the generation sector. Second, although the market is very diverse and highly integrated, both theoretical studies such as Borenstein and Bushnell (1998) and Sweetser (1998) as well as empirical work on the California market (see Borenstein et al. 2000b and Puller 2000) indicate that there is regionalized market power. Third, there is a significant amount of hydroelectric generation capacity in this region, most of it concentrated in the Pacific Northwest and California. It is important to note that, while the share of hydro generation is significant, it does not hold the same kind of dominant share seen in markets such as Norway, New Zealand, or even Chile (see Gilbert and Kahn 1996). Therefore, the interaction between hydro and thermal resources is much more complex in the western U.S. than in those markets. Finally, a single firm controls a significant, if not dominant, share of the hydroelectric capacity in this market. This firm, however, is the U.S. government, manifested in the form of the Bonneville Power Administration (BPA). BPA is responsible for marketing the generation produced by federally owned dams along the Columbia River system. Interpreting the incentives of BPA in a deregulated electricity market is, to say the least, a complex task.

The model described in this paper solves for an equilibrium of a multiperiod Cournot game between strategic producers. While there is an extensive literature on optimal hydro scheduling in the context of a regulated market, there has been very little work done on hydro scheduling in an unregulated, oligopoly environment. Scott and Read (1996) develop a dual dynamic programming approach to numerically solve for an optimal hydro schedule for a strategic firm that controls all the storage hydro capacity in a market with other Cournot producers that control thermal generation. In developing my model, I instead derive the equilibrium conditions analytically, and solve by representing these conditions as a mixed linear complementarity problem (LCP). This approach allows me to both represent multiple firms, each with storage hydro resources, and to introduce a new element, a price-taking fringe whose optimal hydro schedules sometimes operate at cross-purposes to those of the strategic players. By representing the problem as a mixed LCP, I am able to employ existing LCP software (in this case the PATH solver) within the AMPL modeling language. Rivier et al. (1999) also employ an approach based upon the mixed complementarity problem while focusing on the problem of long-term generation operation planning. Kelman et al. (2001) examine a multiyear model of strategic hydro scheduling using a stochastic dynamic programming recursion.

Finally, this model also revisits the market examined in Borenstein and Bushnell (1998). The B&B study took a simplified approach to modeling the production of hydroelectric energy. Since hourly markets were treated as independent of each other, there was no mechanism for optimizing the distribution of available energy *between* hours. Hydro releases were instead assumed to be scheduled using traditional methods, which were best approximated through a peak shaving heuristic that assigns energy in such a way as to equalize, subject to flow constraints, the amount of demand that is left over after subtracting hydro generation. This peak shaving was performed on a regional basis and did not allow producers in the Northwest to respond to higher on-peak prices in California by shifting additional energy to the peak. The model in this paper attempts to examine the impact of such intertemporal and regional redistribution of hydro-derived energy.

The results describe a solution to the optimal allocation problem that is quite different from the solution under regulation or perfect competition. Strategic firms find it optimal to allocate water away from periods with inelastic residual demand and into periods where their residual demand is relatively more elastic. In the context of the model presented in this paper, such a reallocation manifests itself as a movement of water from hours with high demand to those with lower demand. Additional output from the dominant firms in the off-peak hours has little impact on price because such output simply displaces fringe production. A reduction in output on peak, however, can result in significant price increases. Similar to firms that are able to price discriminate between markets, the dominant firms can therefore find it profitable to reduce output in peak hours and concentrate hydro output in the *off-peak* hours.

The results of this analysis also illustrate the importance of explicitly modeling strategic behavior. There is a long history of the use of operations research models in support of regulatory and policy decisions in the electricity industry (see Kahn 1995). Much caution must be applied to the adaptation of such models to a deregulated industry. Models that assume an objective of "least-cost" dispatch cannot capture the range of options available to strategic firms, no matter how well these models represent the operating characteristics of the electricity system. The Federal Energy

Regulatory Commission (FERC) recently recognized the need to update its methods for approving market-based rate authority for electricity producers. One alternative that had been considered was the use of concentration measures, applied to the output of simulations that minimize production costs (see FERC 1998). This paper demonstrates that the use of hydro resources in a way that is directly contradictory to the principle of least-cost production can be very profitable for certain firms. These opportunities would not be detected by an analysis such as the one proposed in 1998 by the FERC.

2. STRATEGIC HYDRO SCHEDULING

In this section, I describe a general model of a deregulated electricity market where some producers control significant hydro and thermal resources. I utilize the Cournot assumption and thereby represent the producers as competing in production quantities. While other equilibrium concepts, particularly that of "supply-curve" competition, have been applied to analysis of electricity markets (see Green and Newbery 1992, and Green 1996), two factors lead me to adopt the Cournot assumption here. First, the focus of this paper is on the scheduling of hydroelectric resources, and hydro scheduling is, fundamentally, a quantity problem. Second, the capacity constraints of both fringe producers and transmission paths play a central role in equilibrium outcomes in the western U.S. electricity market. The supply-curve framework is not well suited to markets where there are multiple asymmetric firms with capacity constraints. Under such conditions, the optimal slope of a supply curve at a given quantity is no longer independent of the slope at other quantities. This greatly increases the complexity of calculating the optimal supply function and weakens its theoretical underpinnings (see Baldick et al. 2000).

In the following subsections, the optimal production problem of each producer is described. From the optimality conditions of this multiperiod production problem, I then describe the conditions for a Cournot equilibrium in terms of the Lagrangian multipliers on the relevant constraints. These conditions imply a series of equations, the solution of which describes a Cournot equilibrium.

2.1. Model

Assume that we have n Cournot producers who control both hydro and thermal generation resources. This framework also allows for small producers that act as price-taking fringe suppliers. Their representation is described in subsequent sections. Let $q_{it} = q_{it}^{Th} + q_{it}^{h}$ represent the total output of firm i in time t, where q_{it}^{Th} is the thermal output and q_{it}^{h} the hydro output of firm i. The thermal output of a firm is required to be nonnegative, and also no more than its total thermal capacity, $q_{i,\max}^{Th}$.

Each strategic producer $i = 1 \ldots n$ has a portfolio of thermal generation technologies with an associated aggregate production cost of $C_i(q_i^{Th})$ and marginal cost of $c_i(q_i^{Th})$. I assume that c is a strictly monotone-increasing function of q^{Th}.

I characterize the hydro systems of the strategic suppliers as having a reservoir of $\bar{q}_i^h$ units of available water (measured in units of energy), $q_{i,\min}^h$ units of required minimum flow, and an instantaneous maximum flow of $q_{i,\max}^h$. I assume that any inflows that occur during the time periods modeled (say a week or a month) do not disrupt the aggregate hydro output decisions of each firm. In other words, the limits on the total reservoir capacity are not binding during this relatively short-term planning horizon, so that any unexpected inflows are added to storage. I also assume that demand, although responsive to price and varying with time, is deterministic. While the stochastic nature of inflows is an important consideration in the operation of hydro resources (see Maceira and Pereira 1996 and Tejadaguibert et al. 1993), this aspect has not been studied in the context of oligopoly markets and would be a useful subject of future research.

Let $p_t(Q_t)$ represent the inverse demand function for the market at time t. Given the output of the other firms, firm i has an optimal production problem defined as

$$\operatorname*{Max}_{q_{it}^h,\, q_{it}^{Th}} \sum_t p_t(Q_t) q_{it} - C_i(q_{it}^{Th}), \tag{1}$$

subject to the constraints

$$q_{i,min}^h \leqslant q_{it}^h \leqslant q_{i,\max}^h \quad \forall\ t,$$
$$q_{it}^{Th} \leqslant q_{i,\max}^{Th} \quad \forall\ t,$$
$$q_{it}^h, q_{it}^{Th} \geqslant 0 \quad \forall\ t,$$
$$\sum_t q_{it}^h = \bar{q}_i^h,$$

where $q_{it} = q_{it}^{Th} + q_{it}^h$, and $Q_t = \sum_i q_{it}$, the total market output in that period. Note that this problem would be separable in t, except for the last constraint, which limits the total hydro production over the T periods. I assume that each firm's single-period profit is concave in its own output. For decreasing price functions, p_t, it can be shown that this problem has a concave objective function so that the problem as a whole is convex.

In the above formulation, I do not allow for the "spilling," or free disposal, of hydro energy. Under some circumstances it may be profitable for a firm to withhold energy by spilling water, but such actions would presumably be easier to detect than other more subtle forms of strategic behavior. I discuss this possibility further in §4.4 in the context of the western U.S. market.

To characterize the optimal solutions, I assign Lagrange multipliers to each of these constraints. The multipliers of interest are ψ_{it} for the thermal output limits, γ_{it} and δ_{it} for the hydro production limits, and σ_i on the total available water to the strategic hydro producer. The term σ is therefore this firm's *marginal value of water* in this model. This value represents the additional profit to the firm that would arise if an additional unit of water could be used for generation during the time frame of the optimization. The optimal solution is characterized by the following KKT conditions:

$$\frac{\partial \mathcal{L}}{\partial q_{it}^{Th}} = p_t(Q_t) + \frac{dp}{dq} q_{it} - c_i\big(q_{it}^{Th}\big) - \psi_{it} \leqslant 0 \quad \forall\, i, t, \quad \text{(CO1)}$$

$$\frac{\partial \mathcal{L}}{\partial q_{it}^{h}} = p_t(Q_t) + \frac{dp}{dq} q_{it} + \gamma_{it} - \delta_{it} - \sigma_i = 0 \quad \forall\, i, t, \quad \text{(CO2)}$$

$$\psi_{it}\big(q_{it}^{Th} - q_{i,\max}^{Th}\big) = 0 \quad \forall\, i, t, \quad \text{(g1)}$$

$$\gamma_{it}\big(q_{i,\min}^{h} - q_{it}^{h}\big) = 0 \quad \forall\, i, t, \quad \text{(g2)}$$

$$\delta_{it}\big(q_{it}^{h} - q_{i,\max}^{h}\big) = 0 \quad \forall\, i, t, \quad \text{(g3)}$$

$$\sigma_i\left(\sum_t q_{it}^{h} - \bar{q}_i^{h}\right) = 0 \quad \forall\, i, \quad \text{(g4)}$$

$$q_{it}^{Th} \leqslant q_{i,\max}^{Th},\ q_{i,\min}^{h} \leqslant q_{it}^{h},\ q_{it}^{h} \leqslant q_{i,\max}^{h}, \quad \sum_t q_{it}^{h} \leqslant \bar{q}_i^{h} \quad \forall\, t,$$

$$q_{it}^{Th}, \psi_{it}, \gamma_{it}, \delta_{it}, \sigma_i \geqslant 0 \quad \forall\, i, t.$$

Combining (CO1) and (CO2) shows that $c_i(q_{it}^{Th}) + \psi_{it} \geqslant -\gamma_{it} + \delta_{it} + \sigma_i$ for all t. When met with equality, conditions (CO1) and (CO2) represent the condition that marginal revenue, $p_t(Q_t) + \frac{dp}{dq} q_t$, equals marginal cost, the traditional optimality condition for production. The economics behind these conditions become more transparent if we assume that there are no binding constraints on thermal capacity, or on minimum and maximum single-period hydro output. These assumptions imply that $\psi_{it} = \delta_{it} = \gamma_{it} = 0$ for all i, t. When applied to each of the n firms, Conditions (CO2) and (CO2) combine to produce $np_t(Q_t) + \frac{dp}{dq} Q_t = \sum_i c_i(q_{it}^{Th}) = \sum_i \sigma_i$. If we define $\epsilon < 0$ as the elasticity of demand, $\frac{\partial Q}{\partial p} \frac{p(Q)}{Q}$, we have

$$p_t(Q_t)\left(1 + \frac{1}{n\epsilon}\right) = \frac{\sum_i c_i(q_{it}^{Th})}{n} = \frac{\sum_i \sigma_i}{n}, \quad (2)$$

which resembles the standard Cournot equilibrium condition that the markup of price over marginal cost is inversely proportional to the elasticity of demand and the number of firms (see Tirole 1988).

In this extreme case when flow constraints do not bind, the economic interpretation of condition (CO2) is also apparent. Each strategic firm will schedule its hydro releases to equate its marginal revenue across all periods in the time horizon. Single-period marginal revenues will be set equal to the marginal value of water, σ_i, which is constant across the time periods of the planning horizon. For firms with market power, this condition represents an important departure from the least-cost optimization case. With an objective of least-cost production, marginal costs are usually set equal to a Lagrange multiplier on the constraint that an inelastic demand level must be met in every hour (the system Lambda value). In the extreme, where flow constraints do not bind, this implies that the residual demand (after hydro allocation) that is to be served by thermal production is the same in every hour (i.e., peak shaving). A firm with market power with an objective of maximizing profit would, in contrast, allocate its hydro production to shave *marginal revenues* rather than demand.

2.2. Price-Taking Fringe Producers

A relevant extension of the above modeling framework is the inclusion of nonstrategic firms. Most electricity markets, including the western U.S., feature producers that are vertically integrated, publicly owned, or relatively modest in size. Producers that fit these descriptions either cannot influence prices, or do not have an incentive to do so. For example, many vertically integrated utilities operate enough capacity to serve their peak demands (plus a reserve margin) and earn a regulated cost-based rate for the production that serves their native demand. When their demand is at lower levels, these utilities sell their surplus production on integrated wholesale markets. Utilities often earn market-based rates on this extra production, but are frequently required to share their profits with their native customers in the form of reduced rates. Such producers would therefore set their production levels according to a different objective than those described in the previous section. When a firm is unwilling or unable to influence price, it will set its production levels to the point where its marginal costs of production equal the market price. Such firms are often described as price-taking, or competitive fringe, firms.

2.2.1. Price-Taking Production Quantities. In the model presented here, the thermal output of price-taking firms can, without loss of generality, be aggregated into a single set of fringe production denoted q_{ft}^{Th}. Instead of the first-order condition (CO1), the equilibrium condition for thermal production from the fringe is therefore

$$\frac{\partial \mathcal{L}}{\partial q_{ft}^{Th}} = p_t(Q_t) - c_i\big(q_{ft}^{Th}\big) - \psi_{ft} \leqslant 0 \perp q_{ft}^{Th} \geqslant 0 \quad \forall\, t, \quad \text{(FR1)}$$

where the symbol $\perp$ indicates complementarity. Similarly, in equilibrium, the fringe firms would set hydro production to a point where their marginal cost equals the market price

$$p_t(Q_t) = -\gamma_{ft} + \delta_{ft} + \sigma_f. \quad \text{(FR2)}$$

In hours where the hydro flow constraints do not bind for any firm, including the fringe, we have $p_t(Q_t) = \sigma_f$. If these flow constraints never bind, prices are levelized across all time periods at a level equal to the fringe value of water, σ_f, even if there are other Cournot firms operating in the market.

An alternative framework for modeling fringe production is to subtract the fringe cost curve from the market demand curve. This was the approach adopted in Borenstein and Bushnell (1998) as well as an earlier version of this paper (Bushnell 1998). Such a framework is analogous to a Stackelberg "leader-follower" model, where the Cournot firms all act as leaders (see Murphy et al. 1983). This approach has several disadvantages for the present application. Because the quantity of fringe hydro production can vary from hour to hour, it is not obvious what the appropriate quantity to subtract from the market demand curve would be. When the fringe is capacity constrained, subtracting the supply curve from market demand will produce a "kinked" demand curve that significantly complicates the process of finding an equilibrium solution.

These alternative approaches can yield somewhat different results, however, and these differences are magnified when the fringe faces binding capacity constraints. The contrast in residual demand elasticity between peak and off-peak periods is not nearly as large when Cournot firms do not anticipate the fringe response. When fringe supply is subtracted from the demand curve, residual demand is far more elastic over the price range where fringe production had not reached its capacity limit. The implications of such assumptions on models of strategic competition would be a useful area of future research.

2.3. Solution Approach

In general, the above equilibrium conditions are met at the solution to a mixed complementarity problem (MCP) formed from those conditions. Similar formulations have been applied to electricity markets in a variety of circumstances. In addition to Rivier et al. (1999), Hobbs (2001) uses a mixed LCP framework to model Cournot in spatial electricity markets. Jing-Yuan and Smeers (1999) and Smeers and Jing-Yuan (1997) employ a variational inequality (VI) approach to modelling Cournot behavior in a spatially dispersed transmission grid. In the following section, I develop an application of the above framework as a mixed LCP (see Cottle et al. 1992) by further restricting the form of the cost and demand functions. The mixed LCP was formulated in AMPL and solved using the PATH solver for the AMPL environment.

3. A LINEAR DEMAND COURNOT-FRINGE MODEL

In this section, I derive the above equilibrium conditions in terms of a model of the western U.S. As described above, I initially assume that there are three Cournot firms, BPA, and the 1997 portfolios of California's largest utilities, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE). I then examine the less concentrated market structure that has emerged over the last several years from the divestitures of thermal plants by PG&E and SCE. I compute the Cournot equilibrium solution for a general linear demand function with piecewise affine marginal costs. Assume that $Q_t = a_t - bp_t$, or $p_t = \frac{a_t - Q_t}{b}$. While the marginal cost curves of most electricity companies are not strictly linear, they can be very closely approximated with a piecewise linear function with only two or three segments. Let $q_i^{Th,j}$ represent the thermal production of type j from firm i with associated marginal cost $c(q_i^{Th,j}) = K_i^j + c_i^j q_i^{Th,j}$ where each thermal production type represents a different segment along a piecewise linear marginal cost curve. The production capacity of each segment, $q_{i,\max}^{Th,j}$, is such that $K_i^j + c_i^j q_{i,\max}^{Th,j} \leqslant K_{ij+1}$, thereby producing a nondecreasing marginal cost curve.

There is also a considerable amount of fringe capacity available. This is the aggregate capacity of roughly 40 utilities in the study region that are either municipally owned or regulated. The thermal capacity is aggregated into a single price-taking fringe firm, with piecewise linear marginal production cost, where each segment j of thermal production has a corresponding marginal cost of $c(q_f^{Th,j}) = K_f^j + c_f^j q_f^{Th,j}$. Fringe production is allocated according to the price-taking conditions described in section §2.2 The strategic firms do not anticipate the production change of the fringe in response to their own output decisions. In the following subsection, I derive the conditions for optimal hydro production of both strategic and fringe firms, which can be solved to produce the Nash equilibrium vector of production quantities.

3.1. Equilibrium Conditions

Under the assumptions of piecewise linear marginal costs and linear demand, the first-order conditions presented in §2.1 reduce to the following set of mixed linear complementarity conditions:

For $q_{it}^{Th,j}, \forall\ i \neq f, j, t$: (CO1)

$$0 \geqslant \left[\frac{a_t - \sum_l q_{lt}}{b_t}\right] - \frac{1}{b_t}\left(q_{it}^h + \sum_j q_{it}^{Th,j}\right) - K_i^j - c_i^j q_{it}^{Th,j} - \psi_{it}^j \perp q_{it}^{Th} \geqslant 0,$$

For $q_{it}^h, \forall\ i \neq f, t$: (CO2)

$$\left[\frac{a_t - \sum_l q_{lt}}{b_t}\right] - \frac{1}{b_t}\left(q_{it}^h + \sum_j q_{it}^{Th,j}\right) - \sigma_i + \gamma_{it} - \delta_{it} = 0,$$

For $q_{ft}^{Th,j}, \forall\ j, t$: (FR1)

$$0 \geqslant \left[\frac{a_t - \sum_l q_{lt}}{b_t}\right] - K_f^j - c_f^j q_{ft}^{Th,j} - \psi_{ft}^j \perp q_{ft}^{Th,j} \geqslant 0,$$

For $q_{ft}^h, \forall\ t$: (FR2)

$$\left[\frac{a_t - \sum_l q_{lt}}{b_t}\right] - \sigma_f + \gamma_{ft} - \delta_{ft} = 0,$$

For $\psi_{it}^j, \forall\ i, j, t$: $0 \leqslant \psi_{it}^j \perp q_{it}^{Th,j} \leqslant q_{it,\max}^{Th,j}$, (g1)

For $\gamma_{it}, \forall\ i, t$: $0 \leqslant \gamma_{it} \perp q_{it}^h \leqslant -q_{it,\min}^h$, (g2)

For $\delta_{it}, \forall\ i, t$: $0 \leqslant \delta_{it} \perp q_{it}^h \leqslant q_{it,\max}^h$, (g3)

For $\sigma_i, \forall\ i$: $\sum_t q_{it}^h = \overline{q}_i^h$. (g4)

Simultaneously solving for the dual and primal variables $\{q_{it}^{Th,j}, q_{it}^h, \psi_{it}^j, \gamma_{it}, \delta_{it}, \sigma_i\}$ for all i, t produces an equilibrium of the multiperiod game. For n producers (including the fringe), J segments to the thermal marginal cost curve, and T time periods, the above conditions produce $nT(2J+3)+n$ complementarity conditions or equality constraints for the same number of variables. In the cases studied in the following section, with four to eight firms and seven time periods, there are 200 to 500 variables.

3.2. The Western U.S. Market

The model described in the previous sections was implemented in the context of the western U.S. electricity market. Each time period t constitutes one hour, and I examine monthly hydro scheduling horizons (i.e., T is the number of hours in a given month). This is the shortest horizon for which firm-level hydroelectric production data are available. Equilibrium outcomes for each month can then be compared to examine the potential impact of the reallocation of water across months and seasons.

Preliminary steps towards electricity industry restructuring were underway in several western states, but most of these have been forestalled by the disruptions experienced during 2000. It now appears that, in the near future, California and Montana will be the only western states with large, privately owned, generation companies that are not regulated at the state level. Many large investor and publicly owned utilities from other western states are players in the California market, but these firms also retain a primary obligation to service their own native markets.

To better account for the close relationship between the California market and hydro conditions in the Pacific Northwest, I combine these two regions into one market. I do not consider the impact of congestion within this combined market. During the first two years of operation of the California Power Exchange market, the two major links between California and the Northwest were simultaneously congested only 4% of the time, although transmission constraints could still impact equilibrium behavior even in the absence of actual congestion (see Borenstein et al. 1999). I take the boundaries of the Northwest market to be those of the U.S. portion of the northwest region of the Western Systems Coordinating Council (WSCC). This combined market encompasses the states of California, Oregon, Washington, Idaho, and Montana, as well as northern Nevada and western Wyoming. Imports from neighboring regions are taken from the actual 1999 firm imports reported by the WSCC (WSCC 2000).

As mentioned above, only California generation companies are assumed to be unregulated. When the market first opened in 1998, two firms, SCE and PG&E, owned the bulk of generation in California. I treat these two firms as Cournot players. PG&E and SCE have since sold off most of their fossil-based thermal generation capacity to five new entrants to the western U.S. power market. To approximate the impacts of these divestitures, I simulate a case with six Cournot firms, BPA, and the five new thermal firms. In this scenario, SCE's portfolio is distributed equally amongst three firms and PG&E's is divided equally amongst the other two. These five firms do not own any hydro facilities, which were not divested. Two other large California generators, San Diego Gas & Electric (SDG&E) and the Los Angeles Department of Water and Power (LADWP) are assumed to be price-taking firms, SDG&E because of its size (about 1/7 of the capacity of PG&E), and LADWP because of its large native demand. I also examine a case where the markets for thermal generation are operating perfectly competitively. In other words, all thermal capacity in California and the Northwest is treated as owned by price-taking fringe firms.

Bonneville Power Administration. The remaining strategic Cournot player in this model is the one additional institution that could be construed as having both significant incentive and ability to influence prices in a less regulated western electricity market, the Bonneville Power Administration. Formed in 1937, BPA's mandate has been to sell power from federally owned water projects to a set of "preference customers," including municipal utilities and rural electric cooperatives, at cost-based rates. In addition, BPA sells considerable amounts of power to aluminum producers in the Northwest and to investor-owned utilities throughout the WSCC. By the early 1990s, BPA faced enormous political pressure to increase its revenue (see Costello and Haarmeyer 1992). With a huge number of sales contracts set to expire in 2001, the agency is currently rethinking its long-term marketing strategy. There is considerable disagreement about what that strategy should be, although almost everyone agrees that BPA needs to increase its revenue.

The analysis below assumes that BPA is constrained only by the *physical* limits of its resources. This assumption understates the *political* and *contractual* constraints faced by the agency. BPA has extensive firm service load obligations, which in turn make it a major customer as well as producer of power in the western U.S. In particular, the minimum output levels of BPA resources are based upon stream-flow requirements and not upon contractual obligations. This model should be understood to be a simplified representation of the political-economic environment in which BPA policies are set. It is nonetheless very instructive to examine what strategies would maximize BPA's revenues, if that were its sole objective, and the impact of those strategies on the western electricity market.

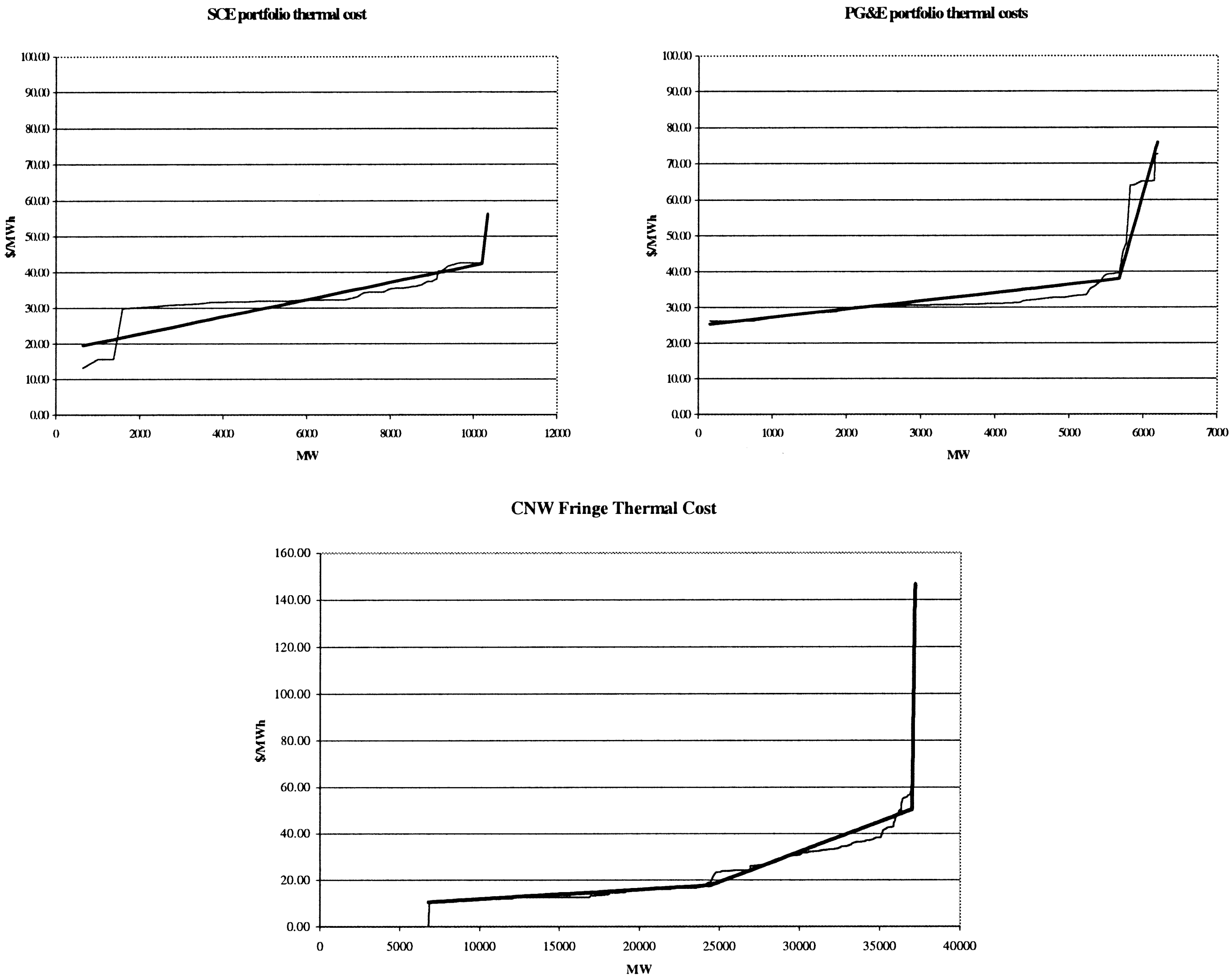
3.3. Suppliers

Initially three firms, SCE, PG&E, and BPA were assumed to be strategic in this analysis. At the beginning of 1998, these three firms accounted for approximately 40% of the generation capacity in the California-Northwest (CNW) region. All the remaining firms were treated as price-taking fringe producers. The thermal and hydroelectric generating capacity of each of these four sets of generation is given in Table 1.

Table 1. Generation capacities (MW).

Firm	PG&E	SCE	BPA	Fringe	Total
Conventional Hydro Capacity	2,676	932	20,212	19,240	43,060
Pump-Storage Hydro Capacity	1,056	206	0	2,350	3,612
Thermal Capacity	6,182	10,331	1,054	37,154	54,721
Totals	9,914	11,469	21,266	58,744	101,403

Figure 1. September 1999 thermal production costs.



Thermal Generation Resources. Thermal production costs were taken from the dataset used in Borenstein and Bushnell (1998). The data include heat rates, variable operating and maintenance costs, and forced outage rates for each generating plant in the data set. These costs have been adjusted to account for 1999 fuel prices. I derate the generating capacity of the thermal units according to their forced outage rates, producing an "expected" generating capacity.

When combined, the individual plant capacities and operating costs produce a stepwise cost function for each firm. In this model, these cost functions are approximated with piecewise linear cost curves of two or three segments. The stepwise cost functions and the linear estimates that I used for September of 1999 are presented for each set of firms in Figure 1. Others (for example, Hobbs 2001) have represented each generation unit as a step in an aggregate cost function in the context of MCP models.

Hydroelectric Generation Resources. There are three key parameters that I used for representing the overall electricity-producing capability of a hydro system. These parameters are the instantaneous minimum and maximum MW output of a system, and the amount of energy, in the form of water in the reservoir, that is available for electricity production during the time horizon of the game. The available energy plays a central role in the results below since the capacity constraints are often not binding.

The maximum generation capacity of each hydro plant in the region is taken from the Energy Information Administration's (EIA) *Inventory of Power Plants.* The energy available for production during each month examined is the actual 1999 monthly energy production of each set of firms taken from EIA's *Electric Power Monthly*. The hydro generation characteristics of each set of firms is given in Table 2.

Estimating the minimum energy production levels, however, is a more complicated task. Flow constraints are measured in units of cubic feet per second (CFS); for use in this model these flows need to be translated in minimum power production levels. The amount of power produced at a dam per unit of flow depends upon the head height of the reservoir, which determines the distance the water falls and thus

Table 2. Hydro generation parameters.

Firm		PG&E	SCE	BPA	Fringe
March	Min Flow (MW)	1,158	269	2,737	2,605
	Hydro Energy (GWh)	1,118	272	8,246	10,585
June	Min Flow (MW)	1,158	269	9,773	3,484
	Hydro Energy (GWh)	1,121	652	9,415	9,926
Sept.	Min Flow (MW)	1,151	258	2,737	2,605
	Hydro Energy (GWh)	928	432	6,136	6,286

Table 3. Load duration curves.

Hour	Number of Hours in LDC	March Demand	June Demand	September Demand
Peak	35	72,006	84,449	81,960
2	75	69,539	79,754	77,536
3	165	67,349	74,153	69,575
4	90	64,145	68,913	65,211
5	105	59,448	63,623	60,276
6	110	54,336	56,330	52,977
7	140/164	48,979	50,202	47,097

the energy released. The MW production is represented by the H/F ratio which gives the MW/KCFS. For this analysis, I used the average H/F ratio for the dam sites for which I had data, which were BPA plants in the Columbia River system. The minimum flows for SCE and PG&E are based upon the dataset used by Kahn et al. (1997) in their simulation of the WSCC system.

However, the H/F ratio is not an entirely exogenous variable. Firms can control the amount of power they release, even if they are constrained on the amount of water that must be flowing in particular systems. One possible extension to this work would be a more complex model of strategic hydro operations that treats some of these parameters as explicit decision variables for achieving a withholding of energy. The minimum flows should be viewed as estimates only. For this reason, sensitivity analysis on this parameter would also be useful. The shadow prices on these flow constraints that are discussed below give some indication of the impact of relaxing these bounds.

3.4. Demand

Starting with detailed hour-by-hour load profiles, I constructed a step function representation of the monthly load-duration curve with seven discrete load levels. The steps had varying durations and the demand level of each step was set equal to the average of the demands covered by those hours in the full load duration curve. Figure 2 shows the load approximation for September 1999. The demand levels for each month are listed in Table 3. The levels in Table 3 reflect an increase in demand of 6% to reflect the capacity to be allocated to reserve margins as well as an adjustment for firm imports and exports from the modeled region into neighboring regions. The more complex production cost models explicitly represent reserves as a separate product, but to my knowledge there has not been a representation of an explicit reserves market in the context of oligopoly competition. Firm imports and exports are taken from the WSCC's summary of estimated loads and resources issued in May 2000.

To calibrate demand *functions* to these forecast quantities, I specified the intercept of each linear demand curve so that each function would equal its forecast demand level at the price that was used to generate that forecast (7.7 ¢/kWh). The slope of the demand curve was constant across periods and was set such that the elasticity of demand at the peak forecast quantity, price point was equal to −0.1. Out of this price, I estimated that 3.5 ¢/kWh would be allocated to transmission, distribution, and other services besides electrical energy. Import levels were estimated by calculating the surplus capacity available in neighboring regions at load levels analogous to those of the modeled region and assuming that all of this capacity was imported into the modeled region.

Figure 2. September 1999 CNW load duration curve.

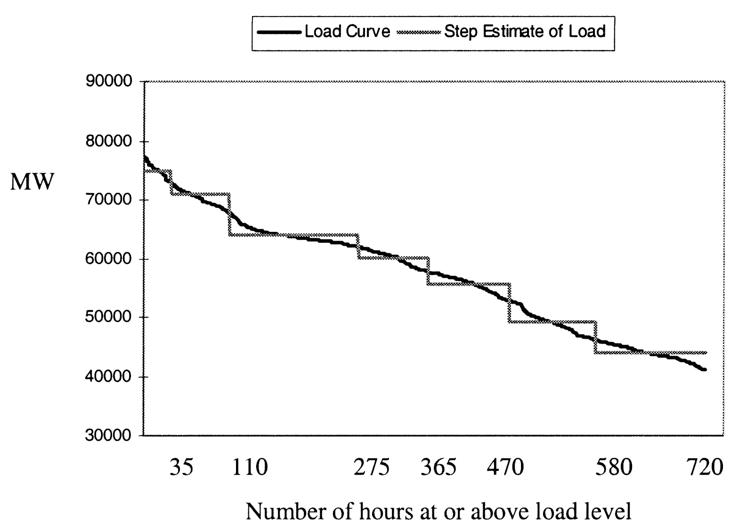
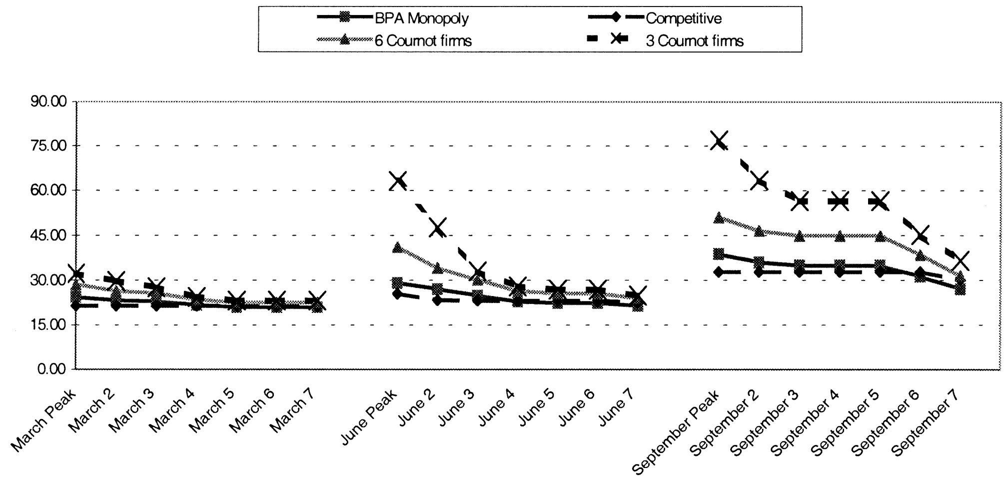


Figure 3. Equilibrium prices by load level and month.



4. RESULTS

Four cases are examined. The first case involves three very large Cournot firms and replicates the market structure before 1998. The second uses six Cournot firms and roughly recreates the market structure as of 1999. A third case examines a market in which BPA is the only strategic firm. The last case treats all firms as perfectly competitive price-taking firms.

4.1. Equilibrium Prices

Figure 3 shows the prices at each load level for these four cases using demand levels, fuel prices, and hydro output from the months of March, June, and September 1999. As expected, peak prices are higher in the cases with more concentrated markets. The severity of market power, measured by the percentage increase over competitive prices, is also disproportionately higher during peak periods when capacity constraints on fringe firms can bind. Table 4 shows the percent markup over competitive price for September under the three strategic cases examined. In the case in which BPA is the only strategic firm, there can be no withholding of energy in a strict sense due to the constraint that prevents the spilling of water. Instead, there is a redistribution of hydro energy from peak hours to off-peak hours, resulting in an increase of prices over competitive levels on peak, but a decrease in off-peak prices relative to competitive levels.

Sensitivity to Demand Elasticity. The elasticity of demand, along with the availability of competitive supply, form the primary factors that impact the ability of firms to exercise market power. It is the relatively inelastic demand for electricity, compounded by a general lack of storage, that makes electricity markets so vulnerable to the exercise of market power. Most California consumers pay retail rates that were frozen for the last three years, although the rates of customers of SDG&E were adjusted to a moving average of the PX price during the latter half of 1999. Even so, there are several reasons why an assumption of *some* response of demand to price is appropriate in this model. Several thousand MW of demand on interruptible rates have been actively curtailed over the last two years. Although these curtailments are triggered by undersupply rather than high prices, in the context of a Cournot model it is the profit implications of undersupply that are driving the decisions of the strategic firms. The model covers not just California, but also five states in the Pacific Northwest. A small number of customers in these regions were on “real-time” rates, but the bulk of customers have a fixed rate that is periodically adjusted to account for the wholesale costs of their utilities. Thus, higher prices will lead to lower future consumption, a factor rational strategic actors would have to consider. Finally, system operators in California and elsewhere have displayed a willingness to reduce levels of operating reserves if the costs of those reserves becomes prohibitive. These reserve costs are directly linked to the wholesale cost of power, and the reduction of demand for this substitute usage for generating capacity has the effect of providing some level of price elasticity in the short run.

Table 4. September markups over perfectly competitive prices.

Demand Level	Peak	2	3	4	5	6	7
3 Cournot Firms	134%	93%	72%	72%	72%	38%	21%
6 Cournot Firms	55%	42%	36%	36%	36%	17%	4%
BPA Monopoly	18%	10%	6%	6%	6%	−5%	−11%

That said, it is difficult to translate the combined impact of the above factors into a single-demand elasticity parameter, or in this case, a slope of a linear demand curve. To gain some insight into the impact of the elasticity assumption, I examined the case with six Cournot firms in September with demand elasticities of -0.2 and -0.05, as well as the -0.1 value used in the results presented in the previous section. As Table 5 shows, peak prices rose from \$51/MWh to \$66/MWh when elasticity was reduced from

Table 5. September prices ($/MWh) with six Cournot firms by load level and elasticity.

Demand Level	Peak	2	3	4	5	6	7
Elasticity −0.05	66.01	52.77	49.67	49.67	49.67	41.89	32.95
Elasticity −0.10	51.00	46.57	44.87	44.87	44.87	38.51	31.50
Elasticity −0.20	46.23	42.97	41.18	41.18	41.18	35.94	30.55

−0.1 to −0.05, compared to a peak price of $45/MWh at a demand elasticity of −0.2.

Overall equilibrium prices were much less sensitive to the elasticity of demand than they were in the study by Borenstein and Bushnell (1998). This is likely due to the differences in functional form of demand (constant elasticity vs. linear) and the alternative treatments of the fringe, as well as the impact of reallocation of hydro energy across hours. This helps illustrate the fact that in addition to the elasticity parameter, several other modeling choices can have nontrivial impacts on the resulting equilibrium prices in oligopoly models. In an industry with strategic firms, it is very unlikely that optimization models will be able to achieve even the level of accuracy with which production cost models forecast regulated rates. Oligopoly models are still important tools for gaining qualitative insight into the nature of imperfect competition in this industry, as well as for providing screening tools for mergers and other regulatory decisions.

4.2. Hydro Production

Several of these cases illustrate how strategic firms can profit from shifting hydro production from peak hours to off-peak hours. As Figure 4 shows, there is a 12% decrease (relative to perfect competition) in hydroelectric production during the peak hours of September in the case with three large Cournot firms. This, combined with the reduction of thermal output from the Cournot firms, results in a peak price that is more than double the peak price under perfect competition (Figure 3).The impact of strategic behavior on hydro output is also significant in June (see Figure 4).

In June, when BPA acts as the only strategic producer, the resulting decrease in peak hydro output relative to perfect competition is roughly 16%. As in September, hydro output is distributed among the off-peak load periods, where prices are marginally decreased relative to perfect competition (Figure 4). The hydro output from BPA in June is described in Table 6. For the cases in which BPA is a Cournot firm (first three rows of Table 6), the reallocation of energy from peak to off-peak is less pronounced in the less competitive cases. In other words, BPA needs to do more reallocation on its own in the more competitive cases to compensate for the absence of withholding from other firms.

The results for all cases with Cournot hydro players follow a similar pattern. In all of the months, we again see the pattern of shifting hydro production from high demand to low demand hours when BPA acts strategically. Peak loads in 1999 were actually higher in June than in September, but much less water is available in the late summer than in the spring. The case with the highest percentage increase in prices was in June with three large Cournot firms, with an increase in peak price of 149% over the competitive level. However, BPA's ability to unilaterally influence prices is muted in March and June relative to the September results. Peak prices are raised 18% above competitive levels by a strategic BPA in September, but only 14% above competitive levels in June. The off-peak decrease in prices by the reallocation of energy is also larger in September than in June.

4.3. Welfare Impacts

There are both equity and efficiency implications to the market power observed in this analysis. The efficiency aspects can in turn be decomposed into inefficiencies stemming from a market quantity that is lower than the competitive levels (the conventional deadweight loss) and those

Figure 4. Aggregate equilibrium hydro production by load level and month.

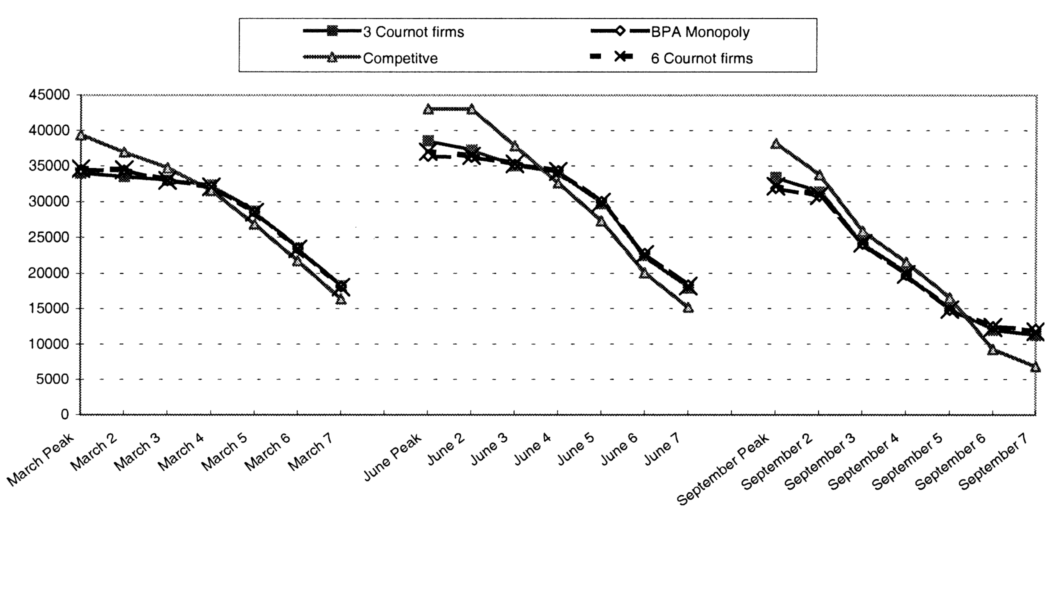


Table 6. June BPA hydro output (MW).

Demand Level	Peak	2	3	4	5	6	7
3 Cournot Firms	15,749	14,417	13,165	12,732	12,642	12,642	12,474
6 Cournot Firms	14,189	13,592	13,252	12,934	12,862	12,862	12,735
BPA Monopoly	13,539	13,361	13,180	13,010	12,972	12,972	12,890
Competitive	20,212	20,212	17,140	9,936	9,773	9,773	9,773

due to a misallocation of production for the quantity that is actually produced. Table 7 reports the results from the case with six Cournot firms, the one that most closely resembled the actual market structure as of 1999. There is a sizable decrease in consumer surplus, but the vast majority of that decrease is a transfer from consumers to suppliers. There is a relatively small amount of loss in consumptive efficiency due to the inelastic demand for electricity. In September, when price increases and the reduction in consumption relative to perfect competition is more substantial, the deadweight loss is somewhat higher (around $3.7 million), but still very small relative to the change in consumer surplus for that month.

Another source of economic inefficiency is the misallocation of supply to meet the resulting demand. In general, the low-cost production of larger firms that are exercising market power is displaced by higher-cost fringe production sources. There are also efficiency losses from an allocation of hydro resources that diverge from the allocation that maximizes total surplus. One measure of this efficiency loss is to consider the total costs of producing a quantity equal to the Cournot equilibrium demand. The third and fourth rows of Table 7 compare the actual production costs from the Cournot equilibrium production levels with the minimal production costs of serving an identical demand profile. The results are related to those for deadweight loss, but are at least an order of magnitude larger. The bulk of the inefficiencies due to market power therefore stem not from market quantities that are too low, but rather from the inefficient production of that market quantity. In each month the total deadweight loss was less than 10% of total production costs.

4.4. Water and Flow Values

The time horizon of the equilibrium models discussed above has been one month. We can also develop some intuition for the potential price and revenue impacts of distributing hydro energy over a longer time horizon by examining the equilibrium water values resulting from these single-month calculations. The most striking result (see Table 8) is the negative value that a Cournot BPA places on its water during all months. Clearly, a strategic BPA would prefer to produce less energy during these months than its reservoir constraint requires it to produce. The requirement that it produce all the potential energy allocated to each month constrains BPA from withholding output to levels that would otherwise maximize its profits. Even so, as demonstrated above, BPA and the other firms are able to elevate prices within periods relative to perfectly competitive levels by allocating energy from periods in which demand is more elastic to those in which it is less. The presence of market power has the opposite effect on the value of water to the price-taking firms. The increase in prices due to market power in turn increases the value of additional energy to these firms.

Because BPA also finds it profitable to shift water from high to lower demand *hours*, one might expect that it would also profit from reallocating energy from high to lower demand *months*. In fact, as shown in Table 8, this is not the case. Water is most valuable (or less negatively valued) in September for all firms, no matter what the competitive outlook of the market is. This is largely due to the fact that the fringe has sufficient low-cost resources to constrain price increases in off-peak hours of every month examined. In all three months there is little difference between the competitive and strategic off-peak prices. In general, a strategic hydro firm that is unable to spill water will want to release it in hours in which it will have little impact on prices. Because the market is relatively competitive at least some of the time in each month, strategic firms do not need to reallocate across months in order to find such hours.

Tables 9 and 10 show the shadow price values on flows for the months of June, under the three Cournot firms

Table 7. Welfare impacts of six Cournot firms relative to perfect competition.

Welfare Impacts (Millions $)	March	June	September
Change in Consumer Surplus	122.34	246.53	434.36
Deadweight Loss from Underconsumption	0.28	1.21	3.69
Cournot Production Costs	321.50	383.18	531.76
Minimum Costs for Cournot Quantity	301.51	351.33	484.42
Total Deadweight Loss	20.27	33.06	51.03

Table 8. Equilibrium marginal water values.

Firm		BPA	Fringe
6 Cournot Firms	March	−132.87	22.51
	June	−125.45	25.52
	September	−57.88	44.87
BPA Monopoly	March	−132.87	22.51
	June	−129.83	22.42
	September	−66.48	35.05
Competitive	March	21.41	21.41
	June	23.19	23.19
	September	32.87	32.87

Table 9. June shadow prices with PG&E, SCE, and BPA Cournot.

Hour	Firm	PG&E	SCE	BPA	Fringe
	σ	12.59	15.51	−121.55	26.83
Peak	$\delta_{i1} - \gamma_{i1}^*$	10.46	6.38	0.00	36.47
2	$\delta_{i2} - \gamma_{i2}$	3.66	4.61	0.00	20.83
3	$\delta_{i3} - \gamma_{i3}$	0.00	2.95	0.00	6.14
4	$\delta_{i4} - \gamma_{i4}$	0.00	1.43	0.00	1.05
5	$\delta_{i5} - \gamma_{i5}$	0.00	0.38	0.00	0.00
6	$\delta_{i6} - \gamma_{i6}$	0.00	0.38	0.00	−0.27
7	$\delta_{i7} - \gamma_{i7}$	−1.33	0.00	0.00	−1.97

scenario and the scenario in which there are six Cournot firms, but PG&E and SCE operate their hydro assets as price-taking firms. It is important to remember that these values represent the *marginal* benefits to the individual producer of relaxing constraints given that the other producers do not change their output. Nevertheless, these values do provide useful insights into how each class of firm would benefit from either relaxing their flow constraints or releasing more energy at specific load levels.

From Tables 9 and 10, one can see that both PG&E and SCE, with their relatively tight flow constraints, are at one of their flow limits much of the time. In the case when PG&E and SCE are Cournot firms, the value of relaxing these flow constraints is relatively small compared to the comparable values to the fringe. In contrast, BPA never reaches one of its flow limits, but has a considerably smaller (negative) value of water. The value to the fringe of relieving these constraints when they are binding can be extremely large. This is illustrated in Table 10, where the shadow prices for the price-taking PG&E and SCE are considerably higher than they were in Table 9, when they were Cournot firms. This is because the marginal revenues of these firms, which are being levelized across periods in Table 9, are lower than the market prices for each hour, which are being levelized as much as possible by these firms in Table 10.

These shadow price values can also be used to form crude estimates of the extent that pumped storage resources might be utilized and the value of such a utilization. Pumped storage is one way of relieving a firm's flow constraints, allowing, for example, a fringe firm to increase peak output and reduce its off-peak output. In essence the value of the water in each hour t is equal to $\sigma + \delta_t - \gamma_t$. To estimate the value of reallocating hydro energy through pumped storage, take the difference between the minimum and maximum shadow values on flow constraints and compare it to that firm's value of water. Since roughly 33% of the energy is lost in the pumping-release cycle, the value of the shadow price differences should be at least 33% greater than the value of water if a firm were going to "pump" some of its pondage hydro energy.

Table 10. June shadow prices with six Cournot firms, PG&E, SCE price taking.

Hour	Firm	PG&E	SCE	BPA	Fringe
	σ	30.10	24.03	−125.45	25.52
Peak	$\delta_{i1} - \gamma_{i1}$	10.99	17.06	0.00	15.57
2	$\delta_{i2} - \gamma_{i2}$	3.99	10.06	0.00	8.57
3	$\delta_{i3} - \gamma_{i3}$	0.00	6.07	0.00	4.58
4	$\delta_{i4} - \gamma_{i4}$	−3.73	2.34	0.00	0.84
5	$\delta_{i5} - \gamma_{i5}$	−4.58	1.49	0.00	0.00
6	$\delta_{i6} - \gamma_{i6}$	−4.58	1.49	0.00	0.00
7	$\delta_{i7} - \gamma_{i7}$	−6.07	0.00	0.00	−1.49

On the other hand, BPA, placing a negative value on its water during June, would prefer to pump simply as a means of wasting energy and achieving a withholding from the market. This observation leads to the conclusion that a profit-maximizing BPA may find it generally profitable to convert water to power less efficiently than if it were a price-taking firm. Although efforts to "spill" water around the turbines would be easy to detect, they could be justified, or even required, by environmental restrictions on river system operations. Other more subtle techniques to manage river flows and reservoir head heights to minimize, rather than maximize, the efficiency of the energy conversion would be virtually impossible to detect.

5. CONCLUSIONS

In the volatile, less-regulated electricity market that has emerged in the western U.S., hydroelectric resources play an important role. While this market features a broad and diverse set of suppliers, several relatively large firms are jointly "pivotal" suppliers during times of high demand. It is during these periods when the production of the large firms cannot be replaced with that of other smaller competitors that the potential for market power is most severe. Hydro resources, with their ability to either smooth demand, or conversely, sharpen the peaks, provide their owners with the opportunity to greatly reduce or further increase the frequency and severity of market power.

The Bonneville Power Administration, which controls vast hydroelectric capacity in this market, is currently one of these pivotal producers. BPA's ability to shift large amounts of energy between off-peak and on-peak markets gives it a unique position from which to influence prices. BPA's strategic position in the western power market needs to be considered in any policy decisions regarding restructuring or, as some have proposed, privatizing the agency. Of course, BPA's ability to influence prices also depends upon the overall competitiveness of the market. In general, when the rest of the market is more competitive, a strategic BPA has to implement a more dramatic reallocation of water from peak to off-peak to achieve even modest increases in overall prices.

In this paper, the limited production capacity of low-cost electricity supply is the primary driving force behind the "bifurcation" of the electricity market into very competitive and less competitive hours. However, such divisions can also be created by such factors as local regulatory intervention, the mixed incentives of different firms, and, especially, transmission constraints. All of these issues can have a significant effect on the degree of competition in the western power market and therefore merit further consideration.

The onset of restructuring in the industry also greatly complicates efforts to quantify the impact of environmental regulations on the operations of hydro facilities. It is entirely possible that such regulations may actually benefit firms that find themselves in dominant positions. By contrast, the economic cost to consumers of certain operating restrictions may be far higher in the presence of market power than would be indicated from studies that implicitly assume that the market is perfectly competitive.

While strategic behavior can have a very large impact on the redistribution of water within a month, the implications of market power for the shifting of hydro energy *between* months appear to be less dramatic. In all cases, both BPA and the fringe firms would prefer to be able to allocate more hydro energy to September from the springtime months. The differential between monthly water values was greater for BPA in the context of the more concentrated, three Cournot-firm market than when BPA alone acts strategically. This differential is even greater for the fringe, which greatly values additional hydro energy in the late fall when it is faced with a market with several Cournot firms.

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