Water and Power: Hydroelectric Resources in the Era of Deregulation in the Western US

James Bushnell*
University of California Energy Institute
2539 Channing Way, Berkeley CA 94720

Revised October, 2000.

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. Hydro electric 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. Even in a regulated environment, this capability provides tremendous advantages. 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.

---

*I am grateful to Severin Borenstein, Chris Day, Wedad Elmaghraby, Richard Green, Ben Hobbs, Edward Kahn, Al Klevorick, Chris Knittel, Bart McGuire, Tristram Scott, Matt White, Frank Wolak, and two anonymous referees for their comments and suggestions. I am also indebted to John Fazio of the Northwest Power Planning Council for both data and discussions.

The advantages provided by hydro electric generation in a deregulated market are even more significant. In the hands of non-strategic firms, the storage capability of hydro power would, 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 could produce a further separation of these geographically and temporally distinct markets. This separation could allow some firms to profitably exploit their dominant positions during peak hours while their competitors are capacity constrained.[1]

In this paper, I attempt to quantify the extent of these advantages 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. Secondly, although the market is very diverse and highly integrated, studies indicate that there is regionalized market power.[2] Third, there is a significant amount of hydro electric 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.[3] Therefore the interaction between hydro and thermal resources is much more complex in the western U.S. than in those markets.[4] Lastly, a single firm controls a significant, if not dominant share of the hydro electric 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

---

[1] The flexible operating characteristics of hydro plants could also give some firms advantages in providing some forms of ancillary services, such as load following and spinning reserve. Assessing the potential for market power in those markets is, however, beyond the scope of this paper.

[2] Borenstein and Bushnell (1998) examined the potential for market power in the California market as does Sweetser (1998) for Colorado. Borenstein, Bushnell, and Wolak (2000) measure the scope and severity of this market power over the first 2 years of operation of California's deregulated market.

[3] See Gilbert and Kahn (1996) for an overview of these and other international electricity markets.

[4] Throughout this paper, "western market" refers to those utilities included in the planning area of the Western Systems Coordinating Council (WSCC).

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 multi-period 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 (1997) 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 focuses on the problem of long-term generation operation planning. Lastly, this model also revisits the market examined in Borenstein and Bushnell (1998). In that paper Borenstein and Bushnell solve for independent, single period Cournot equilibria in roughly the same market. I have had to simplify elements of both these earlier analyses in order to introduce the complexities of a multi-period model featuring multiple firms with hydro capacity.

The results indicate that the dominant firms often face an electricity marketplace that is bifurcated: an 'off-peak' market which is reasonably competitive, and an 'on-peak' market in which some firms possess significant market power. Additional output from the dominant firms in the off-peak hours has little impact on price, since such output is simply displacing 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. This strategy constitutes a major change from current optimal scheduling practices.

The results of this analysis also illustrate the importance of explicitly modeling strategic behavior. 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) is currently proposing that concentration measures, applied to the output of simulations that minimize production costs, be used for 'screening' applications for potential mergers.[5] 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 currently under consideration by the FERC.

2 Industry restructuring in the western US

The electricity industry in the United States has traditionally been characterized by vertically integrated utilities with exclusive franchise arrangements. The franchises left these firms with seemingly dominant positions in the generation of electricity within their own service areas. The integration of utility service areas into larger, regional markets, along the with development of wholesale competition and independently owned generation has done much to undercut these dominant positions (see Joskow, 1997), but significant potential for localized market power remains. The recent introduction of competitive restructuring in the electricity industry, both in the United States and around the world, has inspired a new set of concerns about horizontal market power.[6]

Much of the remaining potential for horizontal market power in the US electricity industry stems from the currently existing physical limits of regional integration. While significant volumes of power are currently traded over long distances, transmission capacity in most regions is not sufficient to fully integrate local markets during high demand periods. This problem exists on both a local (e.g. San Francisco, New York City) and regional (e.g. California, New Jersey) level. Even in areas with significant independent and municipally owned generation capacity, large firms may still find it profitable to reduce

---

[5] See FERC (1998).

[6] This paper is concerned only with horizontal market power which, in this context, is the ability of generation firms to increase prices through their production decisions.

output, exhaust the capacity of these competitors, and exploit their dominant position on the residual demand.[7]

The potential impact of transmission constraints is greatly exacerbated by the fact that electricity is, with some exceptions, not a storable product. The geographic scope of markets therefore can change seasonally and even hourly. Markets like northern California that appear to be very competitive during off peak months or hours still show evidence of significant market power during high demand periods (see Borenstein, Bushnell, and Wolak, 2000). The lack of storage also creates the incentives for rather complex strategic manipulation of transmission constraints.[8]

The western U.S. has experienced a very active wholesale electricity market for over a decade, producing enough volume for the New York Mercantile Exchange to establish a electricity futures contract with delivery specified at two western locations. Even before the current proposals for deregulation, concerns over market power had been sufficient to prevent a proposed merger between Southern California Edison and San Diego Gas & Electric Co. in 1989.[9] However, the deregulation of the California electricity market, accounting for roughly 1/3 of the energy consumed in the WSCC, has generated a heightened level of interest in both the structure and competitive outlook of the western market.

While early discussions about electricity industry restructuring are under way in several states, it appears that, in the near future, California will be the only western state with large, privately owned, unregulated generation companies. Although firms such as PacifiCorp and Enron, through their purchase of Portland General Electric, are players in the California market, these firms also retain a degree of obligation to service their own native markets.[10]

---

[7] Von der Fehr and Harbord, 1993, argue that these considerations dominate the nature of competition in the United Kingdom. Wolak and Patrick, 1996, provide empirical evidence that supports this argument.

[8] Cardell, Hogan, and Hitt, 1997, demonstrate the potential for strategic firms to take advantage of 'loop flow' transmission externalities. Borenstein, Bushnell and Stoft, 2000, show that the interactions between strategic firms in a very simple network can be quite complex when transmission capacity is limited.

[9] See Frankena & Owen (1994)

[10] To the extent that utilities continue to be significant *buyers,* as well as sellers, of power in the restructured market, their incentives to increase prices are significantly reduced.

Primarily due to the factors outlined above, Borenstein and Bushnell, in their examination of the potential for market power in California, treated firms in other states as price-taking fringe players that might export into California any power that is left over after serving their own native loads. The ability of these firms to do this exporting was limited by transmission constraints into both northern and southern California. These transmission constraints often limit the import of power into California from other states in the desert southwest.

The Borenstein and Bushnell (B&B, 1998) study indicated considerably less congestion on paths connecting Oregon and California than that experienced on the paths directly connecting California and the southwest. There were, however, limitations on the availability of competitive generation capacity in the Pacific northwest, particularly in the late summer and early winter months. In these months, hydro resources are at their lowest and demand in the northwest is at its highest. There was therefore little excess capacity available in the northwest for sale in California. Indeed, historically, this region is often buying power from California and the desert southwest during these months. Since Borenstein and Bushnell examined only the California market, their model did not reflect any impact of exports out of, rather than into, California.

The B&B study also 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, which 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. One potentially significant shortcoming of this approach, in the context of a regional model, was that it did not allow producers in the northwest to respond to higher on-peak prices in California by shifting additional energy to the peak. In reality, producers in this region could, and often do, purchase energy from California off-peak, and sell their own power back into California on-peak.

In order to better account for such strategies, in this paper I combine the California market with that of the Pacific northwest. I take the boundaries of the northwest market to be those of the U.S. portion of the northwest region of the WSCC. This combined market is interconnected primarily with the remaining WSCC regions in the Rocky Mountain area, the desert southwest, and western Canada. Table 1 lists the states in the modeled region, and those whose exports into this market are also included.

Region	**States or Provinces in Region**	**Representation**
California-northwest	CA, ID, MO, northern NV, OR, Utah, western WY, WA	Modeled region
Canada	Alberta, British Columbia	Exporter
Rocky Mt.	CO, ND, NB, eastern WY	Exporter
southwest	AZ, NM, southern NV	Exporter

Table 1: Regional Market Definitions

As mentioned above, only California generation companies are assumed to be unregulated. When the market first opened in 1998, two firms, Southern California Edison (SCE) and Pacific Gas & Electric (PG&E), owned the bulk of generation in California. I treat these two firms as Cournot players. 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.[11] PG&E and SCE have since sold off most of their fossil-based thermal generation capacity. 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. These two cases therefore represent the two extremes of the market organization spectrum in the western U.S., one in which 3 firms dominate (the situation circa spring 1998), and one in which all thermal capacity is owned by small, non-strategic firms. The current market structure falls somewhat in between these two extremes.

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.

---

[11] LADWP, unlike the investor owned utilities, will continue to be vertically integrated.

2.1 Bonneville Power Administration

The Bonneville Power Administration (BPA) was formed in 1937 to sell power generated from the newly constructed Bonneville Dam on the Columbia river. BPA's mandate has been to sell power from Federally owned water projects to a set of 'preference customers,' 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. It has been argued rather convincingly that BPA, in fact, kept its preference rates well below its average costs.[12] This led to economically inefficient demand growth, which in turned spawned several unfortunate nuclear generation construction projects.[13]

By the early 1990s, BPA had accumulated enormous debt obligations to the U.S. Treasury and faced increasing operating costs of its hydro projects, partially due to increased requirements for salmon recovery. These factors created enormous political pressure for BPA to increase its revenue. 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* constraints faced by the Agency. In particular, the minimum output levels of BPA resources are based upon stream-flow requirements and not upon contractual obligations. While this may 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, and the impact of those strategies on the western electricity market.

---

[12] Costello and Haarmeyer provide an in-depth overview of the political and economic consequences of BPA policies.

[13] Only one of these plants is currently operating.

3 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,[14] have been applied to analysis of electricity markets, two factors lead me to adopt the Cournot assumption here. First, the focus of this paper is on the scheduling of hydro-electric resources, and hydro scheduling is, fundamentally, a quantity problem. Second, the capacity constraints of both fringe producers and transmission paths play a central role to equilibrium outcomes in the western U.S. electricity market. The supply curve framework is not well suited to markets where the competitive characteristics vary between the different time periods.[15]

In the following subsections, the optimal production problem of each producer is described. From the optimality conditions of this multi-period 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.

3.1 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. This 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 non-negative and also below its total thermal capacity, $q_{i,\max}^{Th}$.

---

[14] See Green and Newbery (1992), and Green (1996) for applications of this concept to electricity competition.

[15] This is due in part to the fact that, to date, supply curve models have relied upon the assumption that the slopes of the demand curves are constant across time periods.

Each strategic producer $i = 1...n$ 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,[16] $q_{i,min}^h$ 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.

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

$$Max_{q_{it}^h} \sum_t p_t(Q_t)q_{it} - C_i(q_{it}^{Th}) \tag{1}$$

subject to the constraints

$$q_{i,min}^h \leq q_{it}^h \leq q_{i,max}^h \quad \forall t$$

$$q_{it}^{Th} \leq q_{i,max}^{Th} \quad \forall t$$

$$q_{it}^h, q_{it}^{Th} \geq 0 \quad \forall t$$

$$\sum_t q_{it}^h = \bar{q}_i^h$$

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.

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}

---

[16] For simplicity, I measure units of water in terms of the energy that can be produced from it. I also assume that the production of electricity from a given unit of water is costless.

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 Lagrangian expression of firm i's problem is

$$\begin{aligned}
\mathcal{L} \;=\; & Max_{q_{it}^{Th}, q_{it}^{h}} \sum_t p_t(Q_t)(q_{it}) - C(q_{it}^{Th}) \\
& - \sum_t \left[\psi_{it} \left(q_t^{Th} - q_{i,\max}^{Th} \right) + \gamma_{it} \left(q_{i,\min}^{h} - q_t^{h} \right) + \delta_{it} \left(q_t^{h} - q_{i,\max}^{h} \right) \right] \\
& - \sigma_i \left(\sum_t q_t^{h} - \bar{q}_i^{h} \right)
\end{aligned}$$

The optimal solution is characterized by the following KKT conditions

$$\frac{\partial \mathcal{L}}{\partial q_{it}^{Th}} = p_t(Q_t) + \frac{dp}{dq} q_{it} - c_i(q_{it}^{Th}) - \psi_{it} \leq 0 \quad \forall \quad i, t \tag{2}$$

$$\frac{\partial \mathcal{L}}{\partial q_{it}^{h}} = p_t(Q_t) + \frac{dp}{dq} q_{it} + \gamma_{it} - \delta_{it} - \sigma_i = 0 \quad \forall \quad i, t \tag{3}$$

$$\begin{gathered}
\psi_{it} \left(q_{it}^{Th} - q_{i,\max}^{Th} \right) = 0 \quad \forall \quad i, t \\
\gamma_{it} \left(q_{i,\min}^{h} - q_{it}^{h} \right) = 0 \quad \forall \quad i, t \\
\delta_{it} \left(q_{it}^{h} - q_{i,\max}^{h} \right) = 0 \quad \forall \quad i, t \\
\sigma_i \left(\sum_t q_{it}^{h} - \bar{q}_i^{h} \right) = 0 \quad \forall \quad i \\
q_{it}^{h} \leq q_{i,\max}^{Th}, q_{i,\min}^{h} \leq q_{it}^{h}, \; q_{it}^{h} \leq q_{i,\max}^{h}, \; \sum_t q_{it}^{h} \leq \bar{q}_i^{h} \quad \forall \quad t \\
q_{it}^{Th}, q_{it}^{h}, \psi_{it}, \gamma_{it}, \delta_{it}, \sigma_i \geq 0 \quad \forall \quad i, t
\end{gathered} \tag{4}$$

Combining (2) and (3) shows that $c_i(q_{it}^{Th}) + \psi_{it} = -\gamma_{it} + \delta_{it} + \sigma_i$ for all t. Conditions (2) and (3) 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 (2) and (3) 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

$$p_t(Q_t)\left(1 + \frac{1}{n\epsilon}\right) = \frac{\sum_i c_i(q_{it}^{Th})}{n} = \frac{\sum_i \sigma_i}{n} \tag{5}$$

which resembles the standard Cournot equilibrium condition that the mark-up of price over marginal cost is inversely proportional to the elasticity of demand and the number of firms.

In this extreme case when flow constraints do not bind, the economic interpretation of condition (3) is also apparent. Each strategic firm will schedule its hydro releases so as 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. Under 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). When 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 would, in contrast, allocate its hydro production so as to shave *marginal revenues* rather than demand.

3.2 Price-taking fringe producers

An extremely relevent extension of the above modeling framework is the inclusion of non-strategic 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. Such producers would therefore set their production levels according to a differen't 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.

3.2.1 Price-taking production quantities

In the model presented here, thermal output choice of price taking firms that, without loss of generality, be aggregated into a single set of fringe production denoted q_{ft}^{Th}. Instead of the first order condition (2), the equilibrium condition for thermal production from the fringe is therefore

$$\frac{\partial \mathcal{L}}{\partial q_{ft}^{Th}} = p_t(Q_t) - c_i(q_{ft}^{Th}) - \psi_{ft} = 0 \quad \forall \quad t. \tag{6}$$

Similarly, in equilibrium, the fringe firms would set hydro production to a point where their marginal cost equals the market price,

$$p_t(Q_t) = -\gamma_{ft} + \delta_{ft} + \sigma_f. \tag{7}$$

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.

3.3 Solution Approach

In general, the above equilibrium conditions are met at the solution to a mixed compelemtarity problem (MCP) formed from those conditions. Such formulations have been applied to electricity markets in a variety of circumstances. In addition to Rivier, *et al.,* (1999), Hobbs (1999) 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.

4 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 assume that there are 3 Cournot firms, BPA, PG&E, and SCE. In addition to its hydro resources, BPA also owns a 1054 MW nuclear unit. In the derivation below, I will refer to PG&E, SCE, and BPA as firms 1,2, and 3 respectively.

I compute the Cournot equilibrium solution for a general linear demand function with affine marginal costs. Assume that $Q_t = a_t - bp_t$, or $p_t = \frac{a_t - Q_t}{b}$ and $c(q_i) = K + c_i q_i$. While the marginal cost curves of most electricity companies are not strictly linear, the marginal cost of the two large thermal producers, PG&E and SCE, are very close to linear for the range of production over which they make the bulk of their output decisions. The linear estimation is more of a problem when representing the competitive fringe. I discuss the implications of the linearity assumption in more detail below.

There is also a considerable amount of fringe capacity available. This is the aggregate capacity of roughly 40 utilites in the study region that are either municipally owned or regulated. The thermal capacity is aggregated into a single, price-taking fringe firm, with affine marginal production cost $c(q_f^{Th}) = K_f + c_f q_f^{Th}$. Fringe production is allocated according to the price-taking conditions described in section 3.2. The strategic firms do not anticipate the production change of the fringe in response to their own ouptut 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.

4.1 Equilibrium Conditions

Under the assumptions of affine marginal costs and linear demand, the first order conditions presented in section 3.1 reduce to the following set of mixed linear complementarity conditions.

For $q_{it}^{Th}, \forall i \neq f, t$:
$$\left[\frac{a_t - \sum_j q_{jt}}{b_t}\right] - \frac{1}{b_t}\left(q_{it}^{h} + q_{it}^{Th}\right) - K - c_i q_{it}^{Th} - \psi_{it} \leq 0;\ q_{it}^{Th} \geq 0\ ;$$
$$\left(\left[\frac{a_t - \sum_j q_{jt}}{b_t}\right] - \frac{1}{b_t}\left(q_{it}^{h} + q_{it}^{Th}\right) - K - c_i q_{it}^{Th} - \psi_{it}\right) q_{it}^{Th} = 0 \qquad \text{EQ1}$$

For $q_{it}^{h}, \forall i \neq f, t$:
$$\left[\frac{a_t - \sum_j q_{jt}}{b_t}\right] - \frac{1}{b_t}\left(q_{it}^{h} + q_{it}^{Th}\right) - \sigma_i + \gamma_{it} - \delta_{it} = 0;\ q_{it}^{h} \geq 0 \quad \text{EQ2}$$

For $q_{ft}^{Th}, \forall i, t$:
$$\left[\frac{a_t - \sum_j q_{jt}}{b_t}\right] - K - c_f q_{ft}^{Th} - \psi_{ft} \leq 0;\ q_{ft}^{Th} \geq 0\ ;$$
$$\left(\left[\frac{a_t - \sum_j q_{jt}}{b_t}\right] - K - c_f q_{ft}^{Th} - \psi\right) q_{ft}^{Th} = 0. \qquad \text{EQ3}$$

For $q_{ft}^{h}, \forall t$:
$$\left[\frac{a_t - \sum_j q_{jt}}{b_t}\right] - \sigma_f + \gamma_{ft} - \delta_{ft} = 0;\ q_{ft}^{h} \geq 0 \quad \text{EQ4}$$

For $\psi_{it}, \forall i, t$: $q_{it}^{Th} \leq q_{it,\max}^{Th};\ \psi_{it} \geq 0\ ;\left(q_{it}^{Th} - q_{it,\max}^{Th}\right)\psi_{it}\quad g1$

For $\gamma_{it}, \forall i, t$: $q_{it}^{h} \geq q_{it,\min}^{h};\ \gamma_{it} \geq 0\ ;\ \left(q_{it}^{h} - q_{it,\min}^{h}\right)\gamma_{it}\quad g2$

For $\delta_{it}, \forall i, t$: $q_{it}^{h} \leq q_{it,\max}^{h};\ \delta_{it} \geq 0\ ;\ \left(q_{it}^{h} - q_{it,\max}^{h}\right)\ \delta_{it}\quad g3$

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

Simultaneously solving for the dual and primal variables $\{q_{it}^{Th}, q_{it}^{h}, q_{ft}^{Th}, q_{ft}^{h}, \psi_{it}, \gamma_{it}, \delta_{it}, \sigma_i\}$ for all i, t produces an equilibrium of the multi-period game. For n strategic producers and T time periods, the above conditions produce $5(n+1)T + n + 1$ complementarity conditions or equality constraints for the same number of variables. The 'squareness' condition, neccessary for PATH to find a solution to the mixed LCP, is therefore satisfied.

4.2 The Western U.S. Market

The model described in the previous sections was implemented in the context of the Western U.S. electricity market. The length of the individual planning horizon that I examine is one month. This is the highest frequency at which firm level hydro-electric 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.

Borenstein and Bushnell's (1998) study of the California market indicated very little transmission congestion between the Pacific northwest and California. Therefore, in this paper, I combine these two regions into a single, integrated market in order to examine the inter-regional impact of strategic hydro scheduling. By treating this region as an integrated market, however, I am unable to represent the impacts of transmission congestion and losses within this region. Imports into the California-northwest market are restricted by both the generation and transmission capacities available in neighboring regions.

4.3 Suppliers

For the reasons given above, 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 hydro-electric generating capacity of each of these four sets of firms is given in Table 2.[17]

Firm	PG&E	SCE	BPA	Fringe	Total
Conventional Hydro Capacity	2,676	932	20,212	19,240	43,060
Pump-Storage Hydro Capacity	1056	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

Table 2: Generation Capacities (MW)

---

[17] Hydro capacities are taken from EIA's 1996 Inventory of Power Plants. Thermal capacities are taken from the WSCC-MAPS dataset and are adjusted for forced outage rates.

Thermal Generation Resources

Thermal production costs were taken from the dataset used by the WSCC for modeling their system using the MAPS production cost model. The data include heat-rates, variable operating and maintenance costs, and forced outage rates for each generating plant in the data set. 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. However, the LCP representation requires me to use linear estimates of these step functions. The stepwise cost functions and the linear estimates that I used are presented for each set of firms in figures 2 and 3. Both SCE and PG&E have large regions of their cost curves that are nearly linear, and the bulk of their output decisions fell in this range. The marginal costs of the fringe, like those of the Cournot suppliers, rise sharply near their maximum capacity. For the demand levels that I examined, however, I find that most of the time the thermal output of the fringe is either at its maximum (with infinite marginal cost), or far enough down its aggregate supply function that a linear approximation to marginal costs is reasonable. The linear approximation will cause the most distortion in those hours in which the Cournot equilibrium price would fall on the sharply rising portion of the fringe's cost curve. Prices in such time periods should obviously be regarded with caution, and further

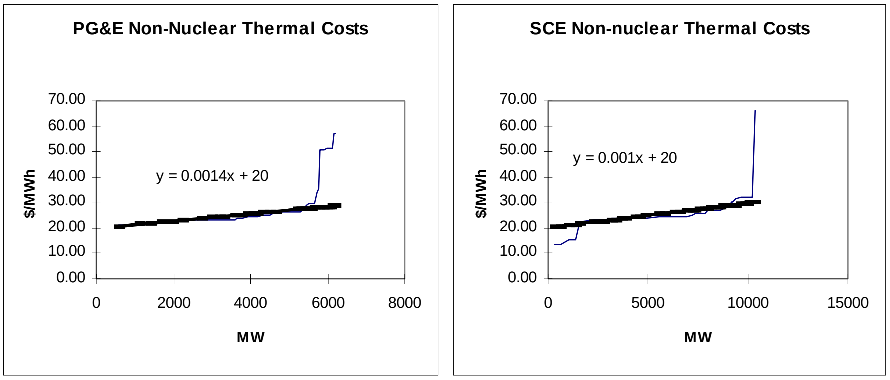

Figure 1: PG&E and SCE 1998 Thermal Producton Costs

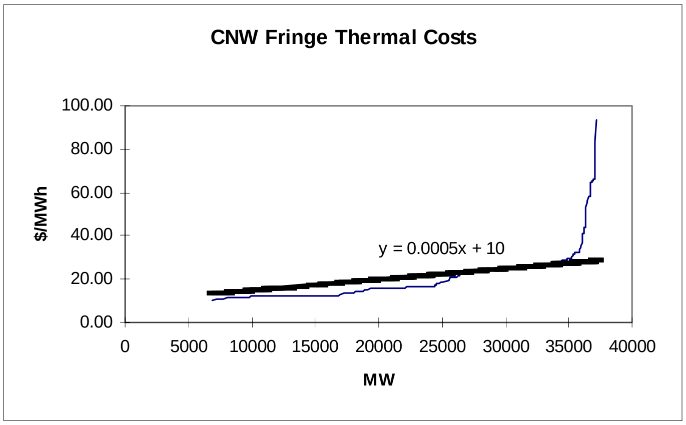

Figure 2: Thermal production cost of fringe firms

examination of these issues is warranted.

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 since, in the Pacific northwest, the capacity constraints are often not binding.

The maximum generation capacity of each hydro plant in the region taken from the Energy Information Administration's (EIA) *Inventory of Power Plants.*[18] The energy available for production during the month of September is based upon historic production levels, taken from EIA's *Electric Power Monthly.* I used a three year average of monthly hydro-electric production levels from 1994 through 1996. The hydro generation characteristics of each set of firms is given in Table 3.

---

[18] Both PG&E and SCE have contracted for additional hydro energy from various sources. To the extent that these contracts allow the purchaser some discretion over the dispatch of these resources, the figures given above will understate the hydro resources controlled by these firms.

Firm		**PG&E**	**SCE**	**BPA**	**Fringe**
March	Min Flow (MW)	1351	258	2737	2605
	Hydro Energy (GWh)	1220	471	7089	7991
June	Min Flow (MW)	1656	469	9773	3484
	Hydro Energy (GWh)	1204	585	8516	8968
Sept.	Min Flow (MW)	1351	258	2737	2605
	Hydro Energy (GWh)	1032	474	4097	4721

Table 3: Hydro Generation Parameters

Estimating the minimum energy production levels, however, is a more complicated task. Most of the minimum production limits are based upon minimum water flows that are imposed for a variety of reasons such as irrigation needs, reservoir management, and the maintenance of salmon habitat. These needs are a source of major contention between the various interest groups in the region, and may very well be subject to change in the coming years.

One element of the controversy involving salmon and white sturgeon runs in the Pacific northwest has been the need to increase water flows during the spring run-off season. If the reservoirs were managed solely to minimize electricity production costs, they would, in general, be filled up as much as possible in the spring in order to produce electricity during the winter peak months. This need for increased springtime flows has created a tension between these two utilizations of the Columbia river system. Additional minimum flow constraints have in recent years been imposed during the spring months. Flow constraints during the month of September, however, have been relatively unaffected by that aspect of the water resources conflict.

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 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 for, which were BPA plants in the Columbia river system. I did not have access to satisfactory data on the flow limits of non-Federal hydro resources in the northwest region. Instead, I multiplied the ratio of BPA's minimum over its maximum capacity by the fringe capacity in the CNW region to estimate the minimum flows of the fringe in the months of March and September. In June, the flow constraints on BPA's resources are extremely large, amounting to nearly half its maximum output. This is due to special fish habitat considerations on the Columbia river system. However, most of the hydro resources of the fringe lie outside of this region. Therefore the fringe's June minimum flows are estimated by applying an increase over their March minimums that is consistent with the increases of PG&E and SCE. The minimum flows for SCE and PGE come from 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. Therefore, the minimum flows should be viewed as estimates only. For this reason, sensitivity analysis on this parameter would also be very useful. The shadow prices on these flow constraints that are discussed below give some indication of the impact of relaxing these bounds.

4.4 Demand

Starting with detailed hour-by-hour load profiles,[19] 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. The demand levels are specified in the first two columns of Table 4. In calculating the Cournot equilibria, demand was increased by 6% to reflect the capacity to be allocated to reserve margins.[20]

---

[19] The load profiles were taken from 1993 EEI load data for each State in the WSCC, these were added together to produce "regional" load-duration curves. These curves were then scaled by the ratio of the September peak demands in 1993 and forecast for 2001.

[20] The WSCC requires a 7% reserve margin on all demand met by thermal capacity and a 5% margin on demand met by hydro capacity, see WSCC (1995).

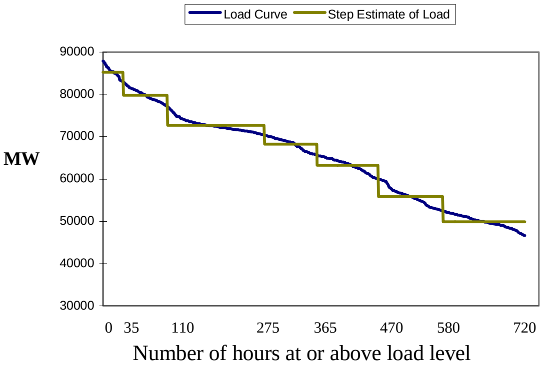

Figure 3: September 2001 CNW Load Duration Curve

Hour	# of hours in LDC	March		June		September	
		Demand	Imports	Demand	Imports	Demand	Imports
Peak	35	73,926	9687	79,147	7429	85,238	3464
2	75	71,384	9267	74,662	8119	79,815	4044
3	165	69,127	7560	69,370	7347	72,680	4650
4	90	65,825	8265	64,418	7169	68,255	4708
5	105	60,985	9197	59,418	7667	63,251	6281
6	110	55,717	10,646	52,526	9285	55,844	8586
7	140/164	50,196	12339	46,734	11,072	49,888	10,830

Table 4: Load Duration Curve and Regional Imports

In order 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.[21] 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 .1. Out of this price, I estimated that 3.5 ¢/kWh would be allocated to transmission, distribution and other services besides electrical energy.[22]

---

[21] The price parameter used to calibrate the demand curves was 7.7 ¢/kWh. This was a weighted average of the CEC's forecast price for California and the 1995 regional price for the Pacific northwest.1995 regional price comes from EIA's 1995 Electric Sales and Revenues.

[22] This figure is consistent with White (1996) who calculates that just over half of utilities' costs are allocated to the energy production function.

4.5 Imports

In this analysis, I took a slightly more simplified approach to the modeling of imports than what was done in Borenstein and Bushnell (1998). For the two U.S. regions adjacent to the CNW region, I constructed equivalent seven-step load duration curves for the month of September at forecast 2001 demand levels. Using the thermal generation data from the WSCC-MAPS data set, I calculated the excess capacity available after reserves. I assumed that all of this capacity would be economic and treated it as must take generation in the CNW region. This calculation likely overstates the level of imports in the off-peak hours, but the overall level of imports was a rather small share of total demand. The overestimate of off-peak imports will bias downward the potential for market power during these hours.

For the Canadian provinces, data are available on exports into the U.S. In September of 1996, for example, British Columbia exported nearly 2000 Average MWh[23] to the U.S. The transmission path linking British Columbia to Washington is rated at 2300 MW. I therefore distributed the BC export energy according to a peak shaving heuristic subject to the 2300 MW maximum. The province of Alberta reported no exports to the U.S. in September of 1996.[24]

5 Results

The first case examined treats BPA, SCE and PG&E as Cournot firms. The hydro and thermal resources of the rest of the western firms are scheduled according to the price-taking equilibrium conditions described above.

In September, the results show that fringe firms are marginal only at the lowest demand level. Prices are much lower at this level than at other demand levels. This scenario provides an example of how strategic firms can profit from shifting hydro production from peak hours to off-peak hours. As figure 5 shows, there is about an 8% decrease (relative

---

[23] An average MWh is the total energy exported in a month divided by the number of hours in the month

[24] These figures are taken from the Alberta Dept. of Energy

to perfect competition) in hydroelectric production during the peak hours when BPA, PG&E, and SCE are acting as Cournot firms. This, combined with the reduction of thermal output from the Cournot firms, results in a peak price that is roughly 3 times the peak price under perfect competition (figure 6).

Demand Level	Peak	2	3	4	5	6	7
Cournot Price ($/MWh)	91.97	82.82	82.82	82.82	70.82	47.69	27.84
BPA Hydro Output (MW)	8438	7370	7370	7370	5969	4323	3250
Fringe Hydro Output (MW)	19240	17077	8896	4157	2605	2605	2605

Table 5: September results when BPA, SCE, and PG&E are Cournot firms

The impact of strategic behavior on hydro output is most dramatic in the month of June (see figure 5). With the 3 large firms are acting as Cournot producers, the resulting decrease in peak hydro output is roughly 17%. The impact of this behavior on price is less dramatic in June than September, however, due to the relatively lower load levels and higher minimum flow requirements. As in September, this output is distributed among the off-peak load periods, where prices are marginally decreased relative to perfect competition (figure 6).

5.1 Price Taking Thermal Generation

As mentioned above, SCE and PG&E have divested nearly all of their non-nuclear thermal generation capacity. The structure modeled in the previous section now overstates the actual concentration of at least the California market. To examine the impact of strategic hydro-scheduling in a less concentrated market, I examined two cases in which all generation resources outside of the BPA system were treated as price-taking fringe suppliers. One case assumed that all firms acted as price takers (perfect competition) and the other assumed that only BPA acted strategically (residual monopolist).

Month	Demand Level	Peak	2	3	4	5	6	7
June	3 firm Courn.	14001	12526	11832	11671	11671	11642	11270
	3 firm Courn.	12175	12035	11903	11811	11811	11799	11588
September	3 firm Courn.	8438	7370	7370	7370	5969	4323	3250
	BPA Monop.	8292	6853	6853	6853	4720	4339	4088

Table 6: June and September BPA Hydro output (MW)

In all months examined, when BPA acts as the only strategic firm it reallocates even more water from peak to off-peak periods than in the 3 firm Cournot equilibrium (see Table 6). The impact of BPA's unilateral output decisions on prices is at times also quite significant. When BPA is the only firm acting strategically, it is still able to induce an 100% increase in prices over competitive levels (figure 6) in September, as opposed to an approximately 200% increase in peak prices over competitive ones when BPA, SCE and PG&E are all Cournot firms.

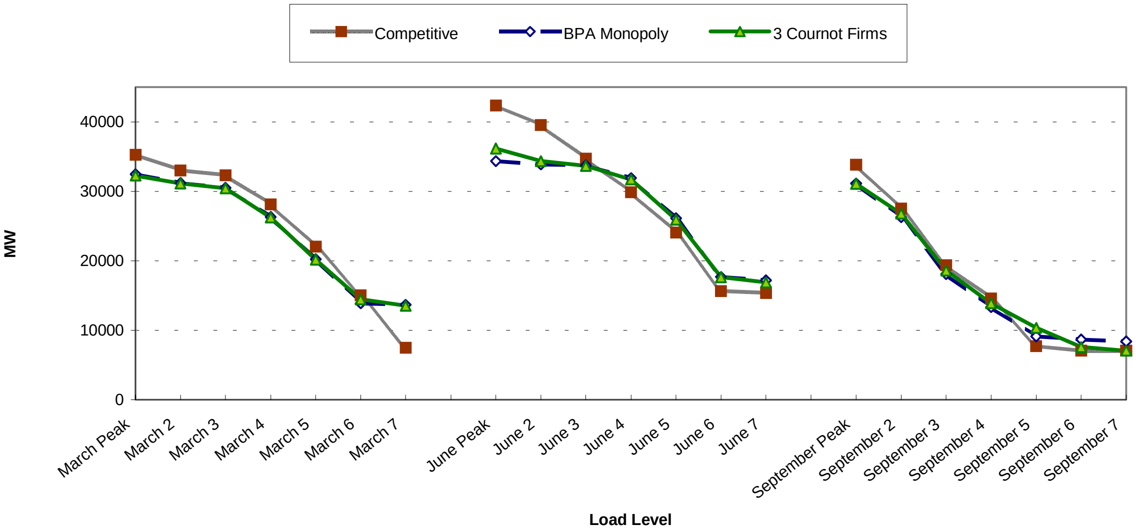

Figure 4: Aggregate Hydro Output

The results for the months of March and June follow a similar pattern, but the price impact is not as dramatic as in September, the month with the most severe potential for market power. In both of these springtime months, we again see the pattern of shifting hydro production from the high demand to the low demand hours when there are 3 Cournot firms. However, BPA's ability to unilaterally influence prices is considerably muted in comparison the September results. This is due to both the increased hydro energy available from all sources and, in June, an extremely high minimum flow constraint.

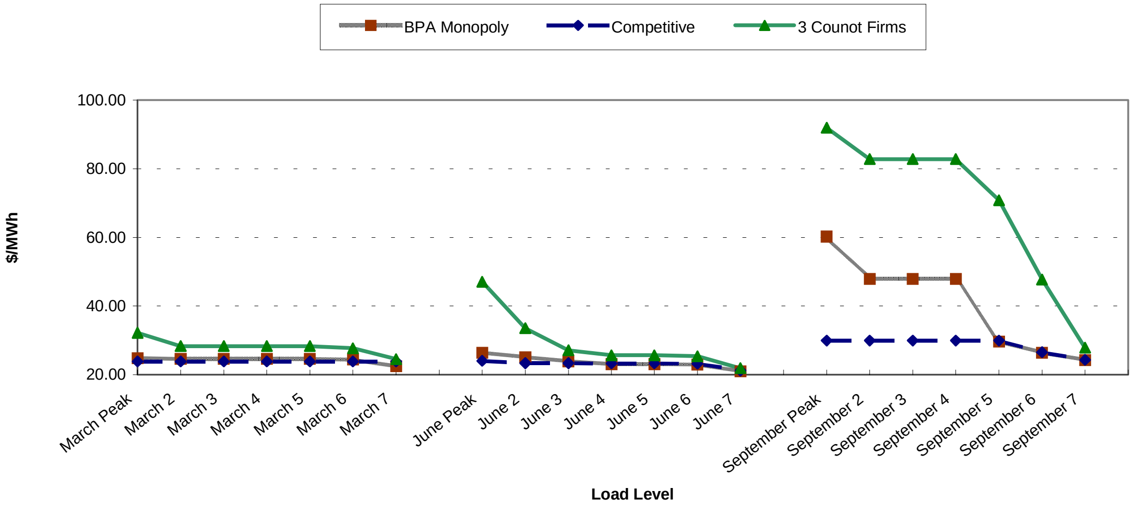

Figure 5: Equilibrium Prices

5.2 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 7) is the negative value that a Cournot BPA places on its water during the spring months. Clearly, BPA would prefer to produce less energy during these months than its resovoir constraint allows 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 so. 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.

Since BPA also finds it profitable to shift water from high to low 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 7, this is not the case. Water is most valuable 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 resources to be marginal in at least the off-peak hours in every month examined. Since 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 hours in which their extra output will have little impact on prices.

Firm		BPA	Fringe
3 Cournot firms	March	-66.56	28.30
	June	-82.07	25.61
	September	10.66	82.82
BPA Monopoly	March	-70.04	24.54
	June	-85.95	23.02
	September	-10.81	47.90
Competitive	March	NA	23.79
	June	NA	23.27
	September	NA	29.91

Table 7: Equilibrium Marginal Water Values

Tables 8 and 9 show the shadow price values on flows for the months of June and September, respectively, under the 3 Cournot firms scenario. 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 8 and 9, one can see that both PG&E and SCE, with their relatively tight flow constraints, are at one of their flow limits most of the time. In part because both firms have broad thermal portfolios to draw upon, the value of relaxing these flow constraints is relatively small. In contrast, BPA seldom reaches one of its flow limits. Similarly, the fringe reaches its flow constraints much less frequently than either PG&E or SCE. However, the value to the fringe of relieving these constraints when they are binding can be extremely large. This is true of the maximum flow constraints in the peak hours of June, and of the minimum flow constraints in the off-peak hours of September.

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. 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 40-50% of the energy is lost in the pumping-release cycle, the value of the shadow price differences should be 50% greater than the value of water if a firm were going to 'pump' some of its pondage hydro energy. The fringe, although it greatly values the ability to reallocate from an off-peak to a peak hour in September, places an even greater value on the water itself. Of course the fringe has thermal resources that it can call upon to generate power that would be 'pumped' during off-peak periods, so we would expect it to do so.

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 far more subtle techniques to manage river flows and resovoir head heights to minimize, rather than maximize, the efficiency of the energy conversion would be virtually impossible to detect.

Hour	Firm	PG&E	SCE	BPA	Fringe
	σ	21.14	17.56	-82.07	25.61
Peak	$\delta_{i1}, -\gamma_{i1}*$	0.00	4.21	0.00	21.50
2	$\delta_{i2}, -\gamma_{i2}$	-2.91	2.91	0.00	7.89
3	$\delta_{i3}, -\gamma_{i3}$	-9.33	0.93	0.00	1.48
4	$\delta_{i4}, -\gamma_{i4}$	-10.81	0.00	0.00	0.00
5	$\delta_{i5}, -\gamma_{i5}$	-10.81	0.00	0.00	0.00
6	$\delta_{i6}, -\gamma_{i6}$	-11.08	0.00	0.00	-0.27
7	$\delta_{i7}, -\gamma_{i7}$	-14.51	0.00	0.00	-37.07

Table 8: June shadow prices with PG&E, SCE, and BPA Cournot

Hour	Firm	PG&E	SCE	BPA	Fringe
	σ	27.04	24.85	10.65	82.82
Peak	$\delta_{i1}, -\gamma_{i1}$	0.00	1.72	0.00	9.15
2	$\delta_{i2}, -\gamma_{i2}$	0.00	0.78	0.00	0.00
3	$\delta_{i3}, -\gamma_{i3}$	0.00	0.78	0.00	0.00
4	$\delta_{i4}, -\gamma_{i4}$	0.00	0.78	0.00	0.00
5	$\delta_{i5}, -\gamma_{i5}$	-1.54	0.00	0.00	-12.00
6	$\delta_{i6}, -\gamma_{i6}$	-4.80	-2.32	0.00	-35.13
7	$\delta_{i7}, -\gamma_{i7}$	-10.77	-4.35	-10.65	-54.98

Table 9: September shadow prices with PG&E, SCE, and BPA Cournot

6 Conclusions

In the less-regulated electricity market that is emerging in the western U.S., hydroelectric resources clearly play a central role. While this market will likely feature a very broad and diverse set of suppliers, it is also likely that several relatively large firms will be the 'pivotal' suppliers during times of high demand. It is during these periods, when the production of the large firms can not 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 the relatively dry early fall, BPA's strategies have a greater effect on price in a *less* concentrated market. The price impact of strategic hydro-scheduling on the part of BPA was much greater when those strategies were superimposed on a perfectly competitive market for thermal generation than was the case when operated in a market with other large Cournot firms. In the spring, however, BPA could not unilaterally raise prices much more than 5% above competitive levels. When all three large firms act strategically in these months, they can have a large impact on equilibrium prices.

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 constrast, 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, 3 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 3 Cournot firms.

In this paper, the intercepts of the demand curves the limited production capacity of price taking firms 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.

References

[1] Borenstein, S., Bushnell, J., and S. Stoft (2000), "The Competitive Effects of Transmission Capacity in a Deregulated Electricity Industry," *RAND Journal of Economics,* **31**(2): 294-325.

[2] Borenstein, S. and Bushnell, J. (1999), "An Empirical Analysis of the Potential for Market Power in California's Electricity Industry," *Journal of Industrial Economics*, **XLVII**(3): 263-284.

[3] Borenstein, S., Bushnell, J., and F. Wolak (2000), "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," POWER Working Paper PWP-064, University of California Energy Institute.

[4] Cottle, R.W., Pang, J.S., and R.E. Stone (1992). "The Linear Complimentarity Problem, Academic Press, Boston.

[5] Cardell, J.B., Hitt, C.C., and Hogan, W.H. (1997), "Market Power and Strategic Interaction in Electricity Networks." *Resource and Energy Economics*, **19**(1-2): 109-137.

[6] Costello, K.W. and Haarmeyer, D. (1992), "Reforming the Bonneville Power Administration," *Cato Journal*, **12**(2): 349-371.

[7] Department of Energy/Energy Information Administration (1995), *Inventory of Power Plants in the United States 1994*, DOE/EIA-0095(94).

[8] Department of Energy/Energy Information Administration (1995), *Electric Sales and Revenues 1995*, DOE/EIA-0540(95).

[9] Federal Energy Regulatory Commission (FERC, 1998). "Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis." Docket No. PL98-6-000.

[10] von der Fehr, N. and Harbord, D. (1993),"Spot Market Competition in the UK Electricity Industry." *The Economic Journal*, **103**:531-546

[11] Frankena, M. and Owen, B. (1994), *Electric Utility Mergers: Principles of Antitrust Analysis*, Praeger, Westport, Conn.

[12] Fudenberg, D. and Tirole, J. (1991). *Game Theory.* MIT Press. Cambridge, Massachusetts.

[13] Gilbert, R. and Kahn, E., eds. (1996). *International Comparisons of Electricity Regulation.* Cambridge University Press. New York, New York.

[14] Green, R.(1996), "Increasing Competition in the British Electricity Spot Market," *Journal of Industrial Economics*, **XLIV**(2): 205-216.

[15] ______ and Newbery, D. (1992),"Competition in the British Electricity Spot Market," *Journal of Political Economy,* **100**(5): 929-953.

[16] Hobbs, B. (1999). "Linear Complimentarity Models of Nash-Cournot Competition in Bilateral and POOLCO Power Markets." *IEEE Transactions on Power Systems.* Forthcoming.

[17] Jing-Yuan, W., and Y. Smeer (1997). "Spatial Oligopolistic Electricity Models with Cournot Generators and Regulated Transmission Prices." *Operations Research*, **47**(1):102-112.

[18] Joskow, P. (1997). "Restructuring, competition, and regulatory reform in the US electricity sector," *Journal of Economic Perspectives*, **11**(3): 119-138.

[19] Kahn, E., Bailey, S., and L. Pando (1997), "Simulating electricity restructuring in California: Interactions with the regional market." *Resource and Energy Economics*, **19**(1-2): 3-28.

[20] Scott, T.J. (1996), "Hydro reservoir management for an electricity market with long-term contracts." Ph.D. thesis, University of Canterbury, Department of Mangement.

[21] Scott, T.J. and Read, E.G. (1996), "Modelling Hydro Resevoir Operation in a Deregulated Electricity Market," *International Transactions in Operational Research* **3**(3-4):243-253.

[22] Rivier, M., Ventosa, M., Ramos, A., Martinez-Corcoles, F., and Toscano, A.C. (1999) "A Generation Operation Planning Model in Deregulated Electricity Markets based on the Complementarity Problem." mimeo. Instituto de Investigacion Tecnologica. Madrid, Spain.

[23] Smeers, Y., and W. Jing-Yuan (1997). "Spatially Oligopolistic Models with Opportunity Cost Pricing for Tranmission Constraints - a Variational Inequality Approach." CORE Disc. Paper 9717, Universite Catholique de Louvain.

[24] Sweetser, A. (1998). "Measuring a Dominant Firm's Market Power in a Restructured Electricity Market, A Case Study of Colorado." *Utilities Policy*, **7**(4): 243-258.

[25] Western Systems Coordinating Council (WSCC,1995), "Reliability Criteria", November.

[26] ---------- (WSCC, 1996a), "Summary of Estimated Loads and Resources," January.

[27] ---------- (WSCC, 1996b), "Path Rating Catalog," Revised, February.

[28] White, M.W. (1996), "Power struggles: Explaining deregulatory reforms in electricity markets," *Brookings Papers on Economic Activity* **SI**: 201-267.

[29] Wolak F.A and R.H. Patrick (1996),"The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market." POWER Working Paper PWP-047, University of California Energy Institute.