PWP-044r

An Empirical Analysis of the Potential for Market Power in California's Electricity Industry

Severin Borenstein and James Bushnell

December 1998

This paper is part of the working papers series of the Program on Workable Energy Regulation (POWER). POWER is a program of the University of California Energy Institute, a multicampus research unit of the University of California, located on the Berkeley campus.

University of California Energy Institute
2539 Channing Way
Berkeley, California 94720-5180
www.ucei.berkeley.edu/ucei

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University of California Energy Institute
2539 Channing Way, Berkeley CA 94720-5180[*]

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ABSTRACT

Using historical cost data, we simulate the California electricity market after deregulation as a static Cournot market with a competitive fringe. Our model indicates that, under the pre-deregulation structure of generation ownership, there is potential for significant market power in high demand hours, particularly in the fall and early winter months when hydroelectric output is at its lowest level relative to demand. The results also show that two of the most important factors in determining the extent and severity of market power are the level of available hydroelectric production and the elasticity of demand.

[*] We would like to thank Shawn Bailey of Southern California Gas Co., and Philippe Auclair, Tom Flynn, and Mark Hesters of the California Energy Commission for their help in providing data and input, Richard Green, William Hogan, Paul Joskow, Ed Kahn, Christopher Knittel, Mike Waterson, Frank Wolak, and two anonymous referees for their helpful comments, and Haru Connolly, Wedad Elmaghraby, and, especially, Christopher Knittel for their excellent research assistance. This research was partially funded by the California Energy Commission under contract # 300-95-007.

1. Introduction

The formation of a less-regulated, more competitive electricity industry is currently taking place in California and many other states in the U.S. Similar restructuring is occurring in many other countries. In California, an electricity spot market began accepting bids for day-ahead supplies of electricity on March 31, 1998. Though the market is running, the exact rules of operation continue to evolve, as does the competitive structure of the market. Many involved in electricity restructuring have expressed concern about supplier market power that may raise prices in a deregulated market. Before the U.S. Federal Energy Regulatory Commission (FERC) will allow full implementation of "market-based" electricity pricing, it must be satisfied that, among other things, no firm would have the ability to exercise significant horizontal market power in the proposed markets.

Traditionally, analyses of the potential for market power in electricity have utilized concentration measures such as the Hirschman-Herfindahl Index (HHI), and the FERC has proposed adopting the HHI as the fundamental screening tool for merger analysis in this industry.[1] There is strong evidence, however, that concentration measures can be misleading indicators of the potential for market power in this industry. A simulation of market outcomes, using available cost data and oligopoly equilibrium concepts can yield far greater insights into the competitive outlook of a market. In this paper, we demonstrate the advantages of such a model relative to concentration measures by simulating Cournot competition between the major suppliers of electricity in California marketplace. We use data on generators in California to evaluate the likelihood of significant market power problems once the market is fully deregulated, which is currently scheduled to occur in 2001.

California's electricity market is centered around two independent institutions. The Power Exchange (PX) serves the role of market-maker by accepting day-ahead supply and, it is hoped, demand bids from the investor owned utilities and others, and then setting hourly spot prices.[2] Buyers in the PX include regulated distribution companies, power marketers and some large industrial customers. The extent to which end user prices reflect the prices in the PX depends entirely on the pricing policies of the distribution companies or power marketers, as they could design virtually any retail pricing scheme including a constant price at all times or a price that moves hourly with the PX price. The Independent System Operator (ISO) has the responsibility of ensuring that the dispatch submitted by the PX and by contracts signed outside the PX meet grid reliability criteria.[3] The ISO also runs a "real-time market," in which it regulates supply

[1] See FERC (1998).
[2] For a more complete description of the PX, see its web site, http://www.calpx.com. Other market makers compete with the PX by putting together transactions between generators and consumers on a bilateral basis.
[3] For a more complete description of the ISO, see its web site, http://www.caiso.com.

and demand to keep them in balance. The ISO then *ex post* charges consumers for use above that scheduled and pays producers for generation above that scheduled.[4]

Previous analyses have outlined several different product markets that are likely to emerge under this new industry structure (see, for example, Borenstein, et al., 1996). These products include spot electrical energy, financial and "physical" long-term contracts, and various services relating to assuring grid stability and reliability. The outlook for market power in these product markets varies. For example, grid service products can be divided into two categories, those for which the competitive outlook is similar to that of spot energy, and those products, such as voltage support, that could experience significant "locational" market power.

In this paper we focus on markets for electrical energy. We assume that the system rules do not give an advantage to one of the various methods of commercial transaction, e.g., trade through the PX, futures contracts for electrical energy, or bilateral contracts.[5] It seems likely that any significant difference in the expected price of energy in one market, such as a price difference between the day-ahead spot market and the price of energy being offered in some longer term contract, would be arbitraged by consumers or marketers that have access to both markets. Thus, for the purposes of this study, we assume that the ability to affect the price of electrical energy depends fundamentally upon the generation capacities and costs of the various potential suppliers.[6]

Unfortunately, one legacy of regulation in California is "stranded investment," assets held by the utility whose market value in a deregulated market would be below the current book value. To reimburse the utilities for these loses, all California electricity consumers will have to pay a surcharge until 2001. Also, during this period, retail rates will be frozen for most consumers. For these reasons, we focus on the structural *potential* of certain firms to exercise market power in California in the year 2001, after the transition period is scheduled to end.

In section 2, we compare various approaches to analyzing market power in electricity generation and explain why we choose to model the large electricity suppliers as Cournot quantity setters. We then discuss the common weaknesses of all static models of electricity competition and the difficulties of modeling the dynamics of the competitive

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[4] The "consumers" who deal directly with the ISO and PX are large industrial customers, power marketers who arrange transactions between generators and end users, and regulated local distribution companies.

[5] There is concern that, in their current form, the governing protocols for the ISO and Power Exchange do not achieve the goal of non-discrimination in transmission access (see Stoft, 1997). While an artificial separation of markets such as those for physical power contracts and those for pool-based spot energy are an important line of research, the first step to market power analysis is to determine the potential of firms to affect price in a market that is otherwise efficient.

[6] In the PX, electrical energy is priced as a distinct product, without associated "capacity payments" for generators, *i.e.*, payments that would be based on capacity made available for generation and would be independent of quantity generated. Though capacity payments are made for some of the ancillary support services (such as availability to provide power for voltage support), we analyze the electrical energy market on the assumption that generator revenue comes solely from per-KWh payments.

environment. In section 3, we present the specifics of the Cournot simulation model and describe how we treat various institutional issues such as demand estimates, transmission constraints, out-of-state generation, and production constraints on hydroelectric generation. The results of the simulation exercise for a variety of demand and supply scenarios are shown in section 4. A key finding is that market power is greatly diminished by divestiture of assets by the largest generators. We find, however, that increases in demand elasticity, such as might result if consumers face time-varying prices and have the technological means to respond, could also do a great deal to reduce market power. In section 5, we conclude with suggestions for further applications and extensions of this approach.

2. Market Power Analysis

2.1 Approaches to Analyzing Market Power in Electricity Markets

In the last several years, the topic of market power in electricity markets has received a great deal of attention due to restructuring initiatives in the UK, US, and elsewhere, as well as to the large number of mergers that have occurred among US utilities. These studies use three general approaches: concentration analyses, various oligopoly models, and detailed production cost simulations.

Due to regulatory and legal precedents, most analysis to date of electricity industry market power in the United States has utilized concentration indices such as the Hirschman-Herfindahl Index (HHI). This type of analysis has dominated regulatory proceedings over utility mergers (see Frankena and Owen, 1994) and the recent filings to the FERC over the proposed California ISO and PX (Joskow, et al. 1996, Pace, 1996). This approach has some general shortcomings – including poor representation of supply and demand elasticities – that are exacerbated when applied to the electricity industry (see Borenstein, et al., 1996). In many industries, such an approach is the best available option since market shares are often the only readily observable firm data. The regulatory history of the electricity industry, however, has produced an abundance of production cost data, making possible the adaptation of more detailed modeling approaches.

The second major line of research on market power in the electricity industry utilizes oligopoly models that explicitly model the strategic behavior of firms. Much of the recent work on this subject that has appeared in the economics literature has used the "supply-function equilibrium" approach to oligopoly modeling. This approach, first developed by Klemperer and Meyer (1989), was adapted to model the UK electricity market by Bolle (1992), Green and Newbery (1992) and Green (1996). In general terms, these studies use stylized representations of generators' costs to develop smooth, continuous cost curves. Players develop optimal continuous bid functions that give output levels for a range of prices. This approach tends to yield several possible equilibria, bounded above by the static Cournot outcome. One notable departure from this approach is that of von der Fehr and Harbord (1993), who point out that the bid functions of individual suppliers in the UK electricity industry have discontinuous jumps. They instead model the UK spot market as a sealed-bid, multiple unit auction.

A third line of research has been the adaptation to regional modeling of utility system simulation models that have been used in the past for planning and regulatory purposes (Kahn, et al., 1996, Deb, et al., 1996). These models represent the complexities of utility system operations in great detail, but are not well suited to modeling the strategic behavior of various suppliers. Bidding strategies for an individual firm can be represented by modifying that firm's cost function, but there is no mechanism for finding equilibrium strategies.

2.2 The Basis for A Cournot Simulation Approach

While the supply-curve analysis approach does incorporate strategic incentives, researchers have not successfully combined that approach with detailed production cost data, because solving for supply-curve equilibria requires relatively well-behaved cost and revenue functions. Furthermore, the most important advantage of supply curve analysis is that it represents well the incentives of a firm when it must bid a single supply curve that will be applied to many different demand states. In California, firms do bid supply curves, but they are permitted to bid a different supply curve for each hour of the day. They are not required to apply the same supply bid to different hours. It is still the case that firms face some uncertainty about exogenous demand factors (*e.g.*, weather) when they submit bids, but the range of this uncertainty is thought to be relatively small (in the range of 3%, according to Hobbs, et al., 1997). Klemperer and Meyer show that all supply curve equilibria are bounded by the Cournot and Bertrand outcomes, and that in the extreme case, in which there is no demand variation, any equilibrium between Bertrand and Cournot is possible. In that case, the Cournot equilibrium represents a worst-case analysis of possible market power in static equilibria. Bolle shows that the most profitable of the supply-curve equilibria become increasingly severe (in terms of price) as the potential demand variation faced by bidders declines.

In comparison to price-setting strategies and a Bertrand equilibrium, the quantity-setting Cournot paradigm seems to correspond to electricity markets much more closely. The Bertrand equilibrium is supported by the assumption that any firm can capture the entire market by pricing below others and can expand output to meet such demand. Since firms have increasing marginal costs of producing electricity at a point in time and since generation capacities present significant constraints in electricity markets, an assumption of Bertrand behavior is not tenable. Capacity constraints on generation are significant in both the medium-term – based upon investments in construction of new capacity – and the short-term, in which plants are rendered "unavailable" due to maintenance and other reliability considerations. This latter, short-term, constraint is most relevant to this study, since the capacity investments of the major players have already taken place.[7] In their

[7] There is one other significant short-term constraint on a firm's output, involving the commitment of generation units to a dispatch process. Most generation units face constraints on how quickly they can begin producing output from a shut down state and how quickly they can increase output to higher levels,

study of the UK electricity market, Wolak and Patrick (1996) argue that the market power of the dominant firms is manifested through those firms declaring certain plants unavailable to supply in certain periods. Thus, the centralized price mechanism and capacity-constrained suppliers in electricity markets (at least during peak periods) support the use of a Cournot model for a base case analysis. This approach allows one to identify the situations in which a producer could increase its profits by unilaterally restricting the amount of generation capacity it makes available to the market.

While the Cournot quantity-setting paradigm does not correspond precisely to strategies in this market, it seems much closer to reality than price-setting behavior, and it allows much more detailed modeling and determinacy in solutions than the supply-curve bidding approach.[8] Furthermore, as a worst-case (static equilibrium) scenario, the Cournot analysis will be useful in indicating if and when policy makers should be most vigilant in scrutinizing markets for possible exercise of market power.

In this study, we represent only the major suppliers of electricity as Cournot competitors. Smaller firms are assumed to be price takers. For a small firm, price-taking output choices differ very little from Cournot output choices. The actual process of simulating price-taking behavior by smaller firms and Cournot behavior by the largest firms is described in the next section. One outcome of our analysis is an estimate of the Lerner index of market power, which measures the markup over the perfectly competitive price. As we see below, the outcomes will depend upon the price elasticity of demand and the cost curves of Cournot competitors and the competitive fringe. Such information is completely ignored in using concentration measures and is very difficult to include in detail as part of a supply curve analysis.

2.3 Dynamic Considerations in Market Power Analysis

None of the models that we have discussed thus far incorporates some potentially important dynamic aspects of competition. First, interactions among firms in a market take place repeatedly over time. In a dynamic model of repeated interaction, it is possible that firms will learn over time to compete less aggressively with one another. Also,

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which causes a "stickiness" in the output they choose to provide. As a result, quantity choices with prices adjusting to equilibrate the market seem more representative than the opposite.

[8] While one could model the industry as either perfectly competitive or perfectly collusive, these extreme models are poor representations of the market. Firms may be able to reduce rivalry through repeated interaction, as we discuss below, but antitrust laws and the natural tendency to cheat on collusive agreements make a *perfectly* collusive view of the electricity market hard to credit. Furthermore, modeling the non-economic factors that might support explicit collusion – such as common background, threats to individuals, or technology for monitoring and enforcing such collusion – is beyond the scope of this study and the authors' expertise. At the opposite extreme, while firms may compete fairly aggressively at times, there are at least a few firms in California that could potentially profitably raise price by restricting output. Thus, a perfectly competitive model of this market, in which no firm recognizes the effect of its marginal production on the price it receives for all of its output, is simply not tenable. Furthermore, it is not possible to analyze the potential for exercise of market power using a model that by assumption does not permit the exercise of market power.

repeated interaction allows a firm to more credibly threaten to punish a rival who behaves non-cooperatively. Faced with a more credible threat of retaliation, a firm is less likely to compete aggressively. Reduced rivalry between firms would lead to higher prices and lost consumer welfare.

Closely related to the repeated interaction considerations is the issue of sales that take place through forward or futures contracts.[9] Such futures markets allow a seller to precommit to output, thus ensuring it a certain quantity of sales. Even for sales of electricity for delivery at a certain point in time, repeated interactions among firms in selling that product – through many days of advanced sales of the good – can have complex effects on the nature of competition. Theoretical work in economics has shown that such repeated interaction can increase or decrease the level of competition between incumbent firms.[10]

A dynamic model of competition, however, would also take into account the effect of actual or potential new entry into the market and possible exit from the market. The possibility of new entry might prove to have a significant disciplining effect on prices and might offset any increased cooperation among incumbent firms in a dynamic setting. If prices over the year are too low to cover a plant's fixed operations and management costs, the plant might shut down, lessening the number of plants and the intensity of competition.

Unfortunately, economic models of dynamic competition in general do not provide a clear guide to either appropriate empirical modeling or the net effect that these factors are likely to have on prices. Furthermore, the models often yield indeterminate results, such as any price between the perfectly competitive outcome and the perfect collusion outcome being a possible equilibrium. Empirical analysis of the dynamic nature of competition among a fixed set of competitors also is notoriously difficult.[11]

Entry and exit considerations could possibly be incorporated into our analysis, but even these effects are difficult to pinpoint with any precision. Analysis of entry depends on making inferences about the costs of production facilities that do not yet exist. While the costs that determine exit from a market exist in theory, in practice this requires difficult and controversial judgments about which costs are truly likely to vary with the operation

[9] We use the term futures market to refer to trades that are contracted for prior to delivery. Whether these take place in formal futures markets – which have standardized contracts and a centralized trading system – or less formal forward markets – in which contracts are not standardized – makes no difference to the argument. Also, whether most such contracts actually result in product deliveries or are settled financially is irrelevant so long as the contract represents an option for physical delivery.

[10] See Allez and Vila (1993) for an example of the former. and Ausubel and Deneckere (1987) and Gul (1987) for examples of the latter. Powell (1993) examines some of these effects in the context of the UK electricity market.

[11] There have been a few attempts to analyze dynamic competition and cooperation (see, for instance, Porter (1983), Ellison (1994), Borenstein and Shepard (1996)), but they have focused on testing very specific aspects of the dynamic models. We are not aware of any work that has applied models of dynamic competition to infer the extent of market power that will be exercised in a market.

of a plant and the level of decommissioning if the plant were closed. The biggest obstacle to incorporating entry and exit effects into a short-to-medium run analysis is the need to include measures of the speed with which such changes are planned and implemented in response to the market environment.

Our analysis does not capture these dynamic aspects of electricity markets. As such, the results of our analysis are imperfect predictors of the degree of competition that will actually take place. Still, in comparison to simple concentration measures that fail to capture many important aspects of competition that our model does incorporate, or in comparison to theoretical models of dynamic competition that have no clear empirical implementation, the modeling framework that we implement is likely to offer greater insight into the degree of competition that may actually obtain in a deregulated California electricity generation market and how that competition may be affected by changes in plant ownership or the market environment.

While we do not analyze these dynamic aspects explicitly, it is possible to interpret our results in a way that recognizes some of these considerations. We analyze the market for a range of demand elasticities. Supply elasticity from small firms can be incorporated as part of the demand elasticity. In fact, in some cases (such as co-generation), it is rather arbitrary whether such changes should be incorporated as supply effects or as (net) demand effects. Thus, longer run entry and exit considerations can be approximated by examining more elastic demand functions. This, of course, raises the question of *how much* more elastic the relevant demand curve should be to incorporate these considerations. Unfortunately, this depends on the speed of entry and exit, and the costs of those firms, data that we do not have. Nonetheless, the more-elastic demand functions that we examine – demand elasticities of 0.4 and 1.0 – while not indicative of current final-consumer short-run demand response, may provide a better guide to the true ability of firms to exercise market power in light of the potential entry and exit in the market.[12]

Another dynamic in this market that is more widely recognized also argues for greater focus on the analyses that assume higher demand elasticity. If prices to final consumers vary over time, consumers will have greater incentive than they now do to adopt conservation and demand shifting technologies. These technologies have significant up-front costs. Increased usage of these technologies will probably occur gradually as consumers learn more about the operation and pricing of the electricity market.

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[12] Wolfram (1996) finds that the oligopoly models such as that used by Green and Newbery (1992) overstate the degree of market power exercised by the largest firms in the UK. While she states that this may be due to the threat of entry or use of forward contracts (as also discussed by Newbery (1995)), she also recognizes that the threat of government regulation and government pressure more generally is also a very plausible cause. Also, Wolfram calculates the degree of market power exercised given the capacity that is made available by the firms. If the exercise of market power takes place significantly through capacity availability decisions, as Wolak and Patrick (1996) show may be the case, then Wolfram's analysis would not capture it.

Finally, our analysis also ignores the political dynamics of electricity pricing. While the Cournot simulation approach can yield extremely high prices at certain times, we don't realistically believe that such prices would persist in practice for any length of time. In the UK, high prices at certain times have led the regulatory agency to induce generators to increase their output and lower prices by threatening greater regulatory intervention. The threat of such intervention has been credited with further damping electricity prices there. Though regulators in California have less power to intervene than in the UK, the threat of a political backlash is still an important factor in firms' decision making, and one that we cannot capture in our modeling.

3. Implementation of the Cournot Simulation Method

3.1 Geographic Markets

The relevant geographic market for California spot electricity in the absence of transmission constraints is generally considered to encompass the member utilities of the Western Systems Coordinating Council (WSCC), which includes utilities in 16 states, 2 Canadian, and one Mexican province. As a simplification of this broad market we have grouped non-California power producers into three smaller markets, one north of California, one to the east and one to the south (see Table 1). Utilities in these markets are assumed to be either regulated or publicly owned, with a mandate to make serving their native load the top priority. To assess the potential for these out-of-state producers to sell output into the California market, we construct residual regional supply curves. The cost curves of individual utilities in each region are combined and the native load of the region is netted out from these supply curves. The remaining generation capacity is assumed to be available to sell into the California spot market, subject to transmission constraints. Out-of-state suppliers are assumed to be price-takers, not individually large enough to profitably restrict sales into California in order to raise price.

Treatment of Transmission Capacity Constraints

The grouping of out-of-state suppliers into three regional power pools facilitates the representation of transmission into California as following two major paths, from the Oregon border into both northern and southern California and from Arizona and Nevada into southern California. We therefore represent the western grid, from the California perspective, as a radial grid with California as a net importing node. Loop flow and other network considerations resulting from the physical nature of electrical flows are not modeled.

The thermal capacity ratings of individual lines on these paths were combined to produce estimates of the aggregate flow capacities along these two paths. For the Arizona/Nevada to California interface, we used the non-simultaneous flow constraint across the "west-of-river" (WOR) boundary of 9406 MW. This boundary includes all AC lines into southern California from Nevada and Arizona. The Inter-mountain link between Utah and Los Angeles provides another 1920 MW of capacity into southern California from the states represented in our southeastern fringe. In addition to out-of-state fringe supply from these states, there is considerable generation capacity located in these states that is owned by California utilities, around 5125 MW of capacity. This capacity consists of low cost coal and nuclear resources that are subject to a myriad of regulation from different state agencies. We therefore treat this capacity, after accounting for transmission losses, as if it is located in California and derate the boundary link by the corresponding capacity. Thus, only about 6021 MW of transmission capacity is available for fringe players located in the southwest region after accounting for the inflow of generation that is owned by California suppliers, but located on the other side of the WOR constraint.[13] In addition we examined the impact of the major north-south path constraint within California, known as Path 15, which we discuss below.

Table 1: Definitions of Regional Markets

Regional Market	States or Utilities Included	Transmission Capacity into California
California	California IOUs, Munis, Water & Irrigation districts, WAPA central valley project	NA
Northwest	British Columbia, Alberta, WA, OR, ID, MT, WY, CO, ND, SD	7870MW[14]
Southwest	AZ, NM, NV, UT[15]	11326 MW
Mexico	CFE	408 MW

Treatment of Transmission Line Losses

When electricity is transmitted over long distances, some amount is dissipated as heat. This becomes a significant factor in a regional model where the transmission is over many hundred miles. In this study, we account for line losses on electricity that is transmitted into California from outside the state. To deal with losses, one must account for two factors: (1) the marginal delivered cost of an additional KWh is $1/(1-l)$ times the MC of production where l is the loss factor, and (2) the quantity of out-of-state production necessary to deliver quantity x is $x/(1-l)$, so to know where on the firm's cost function production is occurring one must scale up from the delivered quantity. Point (2) would be irrelevant if all firms had constant MC with no capacity constraint, but both must be considered if firms have upward sloping MC.[16]

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[13] The transmission ratings in table 1 are total capacity, before we derate to account for in-state ownership.

[14] The aggregate capacity rating along the northwest to California paths have been temporarily reduced to around 6700 MW in response to series of outages in the summer of 1996. We do not consider the impact of this reduction in transmission capacity.

[15] The generation capacity of PacifiCorp, whose service area straddles both of our out-of-state regions, was divided into these two areas according to geographic location of each resource.

[16] For instance, if a firm had $MC=9$ and was delivering 9 units, in the absence of losses, its MC would be 9. With 10% losses, it would have to produce 1.1 units for every unit delivered. So, to increase delivered output from 9 to 10, it would have to increase production from 9.9 to 11. Its MC would be 9 x (11-9.9)=9.9. In contrast, if a firm had $MC=q$ and was delivering 9 units, with 10% losses, the cost of increasing delivery from 9 to 10 would be the cost of increasing production from 9.9 to 11, which would

We do this by decreasing the delivered quantities by a loss factor and increasing the cost per MW by a factor equal to the inverse of one minus the loss factor. The results presented use a loss factor of 5% for all power from out of state. We also decrease the *delivered* capacity of the transmission lines by the loss factor.

be 11.495 (by integrating under the MC curve). The latter example captures both adjustments, the former only adjustment (1).

3.2 Suppliers

Our focus is on the electricity spot market in California. We assume that utilities located in neighboring states, while significant in the aggregate, are not sufficiently large individually to attempt to influence prices in California.[17] We assume that these firms act as price takers in the California market, selling into the California market (after serving their native load) up to the point that their marginal cost is equal to the price in the market. We make a similar assumption for the many small municipal utilities and irrigation districts within California, whose combined generation capacity is about 10% of the total capacity owned by California utilities and for independent power producers that are operating under long term contracts. We represent the three large investor-owned utilities (IOUs) in California – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) – as Cournot competitors facing a price-taking fringe consisting of both in-state producers and out-of-state electric utilities.

The Los Angeles Department of Water and Power (LADWP) also owns a significant amount of California's generation capacity. LADWP, however, will continue to be a net *purchaser* of electricity, offsetting any interest it might otherwise have in increasing prices.[18] Although LADWP may be a net supplier in many hours, its interest in raising the market price by withholding supply would be directly related to the size of its *net* supply during those hours. We assume LADWP's net supply is a very small part of the electricity market in all hours. We therefore treat LADWP as a price-taking fringe supplier.

[17] One potential exception to this assumption is the federally-managed Bonneville Power Administration, which controls a large share of the generation capacity – mostly hydro-electric – in the Pacific northwest. Bushnell (1998) examines BPA's potential for market power in the context of the broader western U.S. electricity market.

[18] In contrast, the distribution affiliates of the IOUs will continue to be regulated and will most likely be able to pass on electricity purchase costs to their customers.

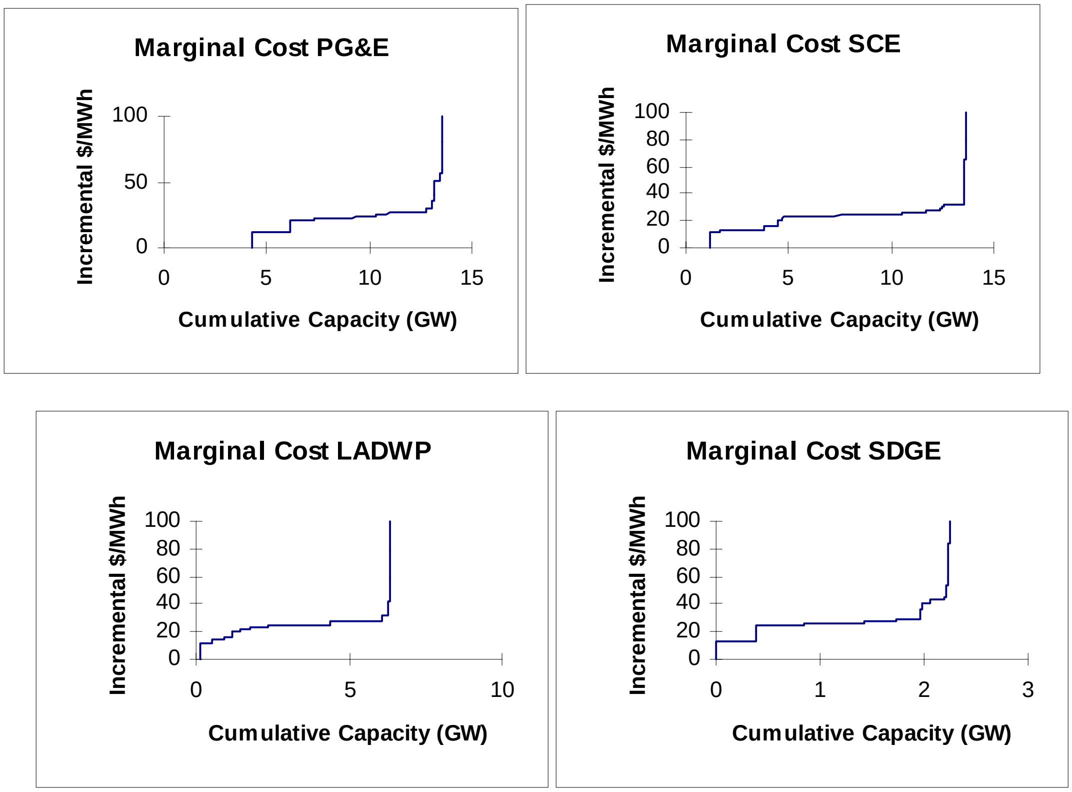

Figure 1: Production Costs of California Suppliers

Using plant heat-rate and operating cost data obtained from the California Energy Commission and other sources (see Appendix B), we construct marginal cost functions for each utility in California and the western United States, western Canada, and northern Mexico. The marginal cost functions of the small California producers are combined into a single, in-state fringe supply function, $S_{CA}^{f}(P) = \sum_{i=1}^{F} s_i(P)$, where F is the total number of firms in the in-state fringe.[19] Figure 1 shows the cost-curves of the four largest California suppliers. Figure 2 shows the aggregated cost-curves of the fringe suppliers (excluding LADWP from the California in-state fringe figure).[20] For the out-of-California areas, the brackets in the figures indicate the forecasted minimum and maximum hourly native demands for 2001. The residual supply available for export to California would be the curve to the right of the native demand quantity at any point in time.

Treatment of the Price-Taking Competitive Fringe Producers

To analyze competition among the Cournot firms in this market, we first control for the effect of price-taking firms (small California producers, LADWP, and the out-of-state fringe) by subtracting the aggregate supply of these fringe firms from the market demand. From this, we obtain a residual demand curve that the Cournot firms in the market would face. To obtain the aggregate fringe supply at any given price, we add together the quantity that each of the price-taking firms would produce if it produced every unit of output for which its marginal cost was less than the price. We then subtract this quantity from the market demand quantity at that price to obtain the residual demand quantity at that price.

$$D_r(P) = D(P) - S_{CA}^{f}(P) - Min(S_{MX}^{f}(P), TR_{MX}) - Min(S_{NW}^{f}(P), TR_{NW}) - Min(S_{SW}^{f}(P), TR_{SW}) \quad \textbf{(1)}$$

where *D(P)* is the market demand function, S_j^F represents the fringe supply curve for region *J* (in-state, Mexico, the Northwest region, and the Southwest region), TR_J represents the transmission constraint between region *J* and California, and $D_r(P)$ is the residual demand curve faced by Cournot players in California.[21] The resulting residual demand function is more price elastic than the original market demand function. This is the demand over which the Cournot firms are assumed to compete.

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[19] The analysis assumes that each plant has a constant marginal cost up to capacity. Consideration of non-monotonic marginal cost functions for individual plants would greatly increase the complexity of the simulation and, possibly, lead to non-unique or nonexistent equilibria.

[20] The production capacities shown in figures 1 and 2 reflect the instantaneous output capacities of pondage-hydro resources as production with a marginal cost of zero. Due to water limits, output from these units is often far below the instantaneous capacity. We discuss the treatment of hydro resources below.

[21] Note that in equation (1), the S^f and *TR* values for non-California regions have been adjusted for transmission losses in the manner described in section 3.1.

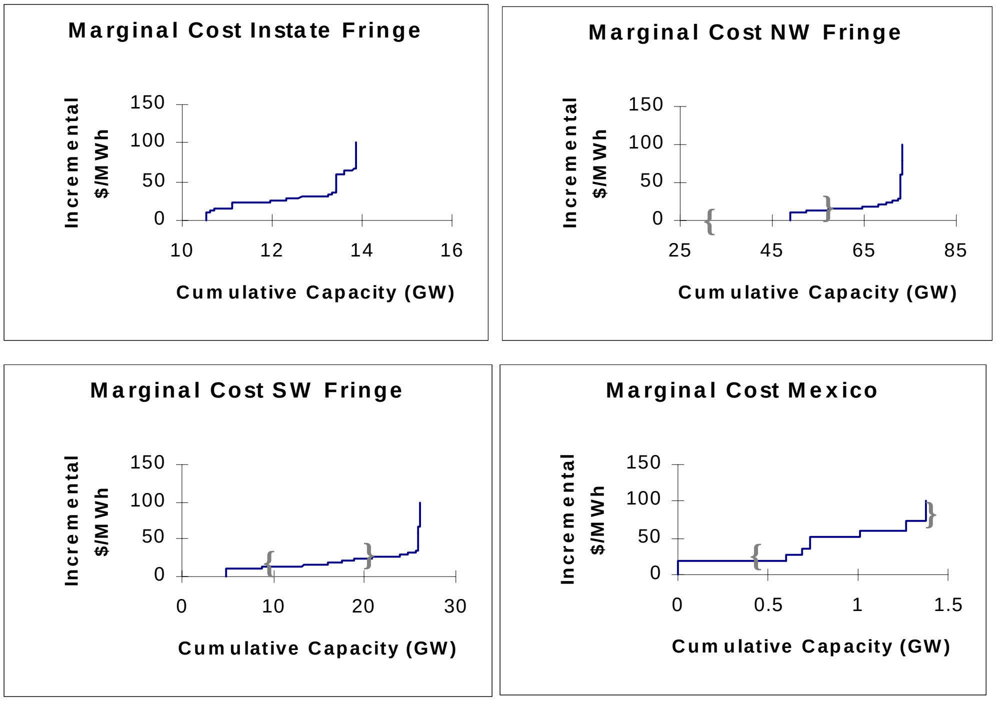

Figure 2: Production Cost of Price-Taking Fringe Suppliers

Treatment of Nuclear Power Plants and Independent Power Producers

Nuclear generation capacity is being treated as a special case in California's electricity market. Current policy would guarantee a level of capital cost recovery on these units and set an energy price on nuclear output at estimated levels of "going forward" costs, including variable costs and fixed O&M, a rate unrelated to the market price. Facing such an agreement, utilities would either operate their nuclear plants at a high capacity factor in order to recover their fixed operating costs or choose to decommission them. Since, however, decommissioning of nuclear plants would likely threaten any agreements to recover capital costs, we assume for this study that these nuclear units are available as "must-run." To do this, we add their capacities to the competitive fringe at a zero marginal generation cost.

Similar conditions apply to the bulk of the independently owned generation in California. Much of this generation, also known as 'qualifying facilities' (QFs), operates under extremely favorable contract terms. These terms provide the incentive for most of these producers to operate as baseload, or must-take plants. We therefore represent this capacity as zero-cost fringe production.

Treating these regulatory must-take plants that are owned by Cournot firms as part of the competitive fringe has the effect of taking them out of strategic consideration by the firm. In considering the benefits that it would get from restricting output and raising price, the firm would then not include extra revenue on the output of such a plant. Furthermore, the firm then does not have the ability to restrict the production from these plants in order to raise the price in the market. These factors correspond to the relationship of an IOU in California to a plant that it owns, but that is classified as regulatory must take: the firm does not have the ability to restrict that plant's output and its compensation for that plant's production is not tied to the market price. Thus, placing an IOU-owned plant in the competitive fringe (with a zero bid) is equivalent to treating it as regulatory must take.

Treatment of Hydroelectric Generation

As our results will show, the amount of available hydro power in the Pacific northwest and California plays a large role in determining the extent and severity of market power. The treatment of hydroelectric generation is more complex than any other production technology because there are important intertemporal constraints on production. At many points in time, increasing production from hydro in one period will lower the production that is possible in another period on a one-for-one basis. This raises the question of how hydro would be optimally scheduled. We treat the hydro scheduling problem as if it takes place in a market with no uncertainty. We discuss below how this assumption affects the analysis.

If a producer faced no uncertainty and no constraint on instantaneous hydro production, then it would schedule hydro so as to equalize the marginal profit that it earns from one more unit of electricity production across all times in which the hydro is in use. For example, consider a group of many small price-taking hydro producers of electricity. If the price in time period A were higher than the price in period B, then these producers would have an incentive to move hydro production from B to A, reducing supply during period B and raising supply during A. As the firms did that, however, price during period B would increase and price during A would decline. Only when the prices were equalized, would the incentive to move output from B to A disappear.

For a firm with market power, the incentives are quite similar. In that case, however, the producer would always want to move hydro output to the time period in which its *marginal revenue* was highest, rather than to the period in which the *price* it received was highest. So, if a firm with market power were producing with electricity from hydro in each of two periods, A and B, and if at current production levels its marginal revenue during period A were higher than its marginal revenue during period B, then it could increase its profits by decreasing production during B and shifting that amount of production from hydro to period A. This would raise its total revenue without affecting its total costs and, thus, would increase its profits.

This simple analysis, however, is complicated by two factors. First, this analysis assumes that producers can produce unlimited amounts of electricity from hydro during a given period so long as the aggregate hydro production constraint is not binding. In fact, there are important instantaneous production constraints in production from hydroelectricity generators. If a firm's hydroelectric generators have a maximum instantaneous production of K, then the firm cannot produce more than K units of output from hydro during a period even if the firm's marginal revenue in the period remains higher than in another period in which it is using hydro. Second, almost all hydro systems have *minimum* instantaneous flow constraints related to the ecological needs of the river systems. Thus, if a firm with market power were producing electricity from hydro in each of two periods, A and B, and if at current production levels its marginal revenue during period A were higher than its marginal revenue during period B, then it would transfer hydro production from B to A until (1) the firm's marginal revenues in the two periods were equalized, or (2) production in B is at its minimum output level, or (3) the maximum instantaneous hydro production during period A were reached. Table 2 shows the relevant parameters for hydroelectric production that were used in this study. The values for energy produced were primarily derived by taking the average of the energy produced in each of these months over 1992-95.

Table 2: Hydro-electric energy and capacity values

	March	**June**	**September**	**December**
California Energy Produced* (MWh)	3,834,000	4,335,000	2,342,000	1,715,000
Min Flow(MW)	2,604	2,947	2,947	2,305
Max Flow(MW)	8,674	9,296	9,296	8,680
Southwest Energy Produced*(MW)	963,000	1,132,000	835,000	805,000
Min Flow(MW)	458	529	529	451
Max Flow(MW)	4,696	4,747	4,689	4,689
Northwest Energy Produced (MW)**	16,802,000	18,553,000	11,575,000	16,736,000
Min Flow(MW)	13,506	13,632	13,632	13,422
Max Flow(MW)	48,861	48,718	48,718	48,776

* *Source:* Energy Information Administration, *Electric Power Monthly*.
** *Source:* EIA, *Electric Power Monthly* (US generation) and WSSC Summary of Estimated Loads and Resources Data, January 1, 1996 (Canadian generation).

Although it is relatively straightforward to characterize a Cournot competitor's optimal allocation of hydroelectric energy under certainty, it is much more complicated to solve for these values. We instead use an approximation of the optimal hydro distribution based upon a technique known as "peak-shaving". We allocate the available hydroelectric production in a month across hours of the month by simply allocating hydro to the highest demand periods (subject to minimum and maximum flow constraints), thus "shaving" the peak demand quantities. This corresponds to a firm's optimal allocation of hydroelectric energy only if demand level is a perfect indicator of the firm's marginal revenue. To the extent that marginal revenue is imperfectly correlated with demand, this approach could misallocate hydro energy across periods and could overstate or understate the exercise of market power.[22]

[22] Scott and Read (1994) examine the strategic scheduling of hydro in a market with multiple Cournot firms, where one firm controls all the pondage hydro resources. Bushnell (1998) extends this analysis to a market with multiple strategic hydro firms in the context of the western U.S. market. He finds that some firms can increase profits by shifting hydro production away from peak towards off-peak periods. This implies that the assumption we use here will understate market power in peak periods.

The second complicating factor is the fact that hydro also is used to respond to unforeseen supply and demand shocks to the system. Hydro is an attractive source for responding to sudden supply needs because it has low start-up costs and generation can begin with very little delay. As a result, companies that own hydro generation often hold some hydro capacity in reserve for use in responding to unforeseen needs. For these same reasons, hydro resources are also used in mid-level demand hours to avoid committing thermal units that would be used only briefly or at a low output level. Modeling these considerations even in a perfectly competitive context is extremely complex. Therefore, we have not incorporated the unit-commitment and reserve capacity functions of hydro for capacity into the model. This also implies that our hydro allocation may be somewhat greater in peak hours than it would be in actual use, which would tend to cause our results to understate market power.

Treatment of Reliability Must-Run Plants

In their supplementary PX filings to the FERC on market power issues, (Joskow, et al., 1996, Pace, 1996) all three California investor-owned utilities identified several localized voltage-support and contingency constraints that they felt necessitated the operation of specific generation units in order to maintain reliability standards at present levels. Some of these constraints reflected localized market power for reliability services, some reflected the market power in the energy market for sub-regions of California that is induced by transmission constraints within the state. As an interim solution, the utilities proposed option contracts on the generation of these units that would be held by the ISO and would be called whenever the ISO felt that a unit was needed for reliability service (see Joskow, et al., 1996). The option price would be set using cost-based estimates[23] and function as a price-cap form of incentive regulation when in effect. The utilities also identify several network improvements that would mitigate the need for certain must-run units. The identity and future ownership of these units and the conditions under which they would be considered must-run are still largely unresolved. We therefore do not simulate a specific set of reliability must-run units in this study.

3.3 Demand

We represent the demand for electricity in California with a constant elasticity demand function of the form $Q = kP^{-\varepsilon}$ where Q is market demand, P price, and ε the price-elasticity of demand.[24] We have run simulations for elasticities 0.1, 0.4, and 1.0, a range

[23] Among other contentious elements of this plan, there is some dispute over what costs should be included in this option price. See Jurewitz and Walther , 1997. The contracts utilized during the first year of market operation created significant incentive problems and are the subject of ongoing negotiations. See Wolak and Bushnell, 1998.

[24] We also performed several simulations using a linear demand curve set such that the desired elasticity was attained at the forecast price-quantity point. The results of these simulations are included in the appendix. A major drawback of the linear demand function is that the horizontal intercept for, say, an elasticity of .1, was only $1023/MWh. It is unrealistic to assume that demand would be completely curtailed by prices in this range. Prices in the UK have reached $1000/MWh a number of times and have

covering most current estimates of short-run and long-run price elasticity. The constant *k* was adjusted so that the demand function through a price-quantity pair taken from the CEC's forecasted average electricity price and demands for the year 2001. This year was selected as a target date for the expiration of many of the regulatory side-payments that will likely distort the production decisions of both large and small producers. The CEC demand forecasts assume a constant electricity price in the year 2001 of 9.3¢/kwh. We use an estimate of 4¢/kwh as the portion of the retail price attributable to local transmission and distribution costs.[25] This figure is in line with the estimates of electric utility sector costs recently undertaken by White (1996). This transmission and distribution cost was added to the marginal costs of all producers in order to align their generation costs with the benchmark point of the demand curve.

Table 3: 2001 Forecast Peak Demands (MWs)

	March	June	September	December
California	38036	49528	54120	41471
N. California	12780	17533	16669	13934
S. California	25256	31995	37451	27537
Northwest	52613	48628	46914	56526
Southwest	15458	19814	19472	16710
Mexico	906	1336	1379	960
WSCC Totals	107012	119306	121885	115667

In addition to satisfying demand, a certain amount of generation capacity will apparently be necessary for satisfying reliability requirements such as spinning reserve. The California restructuring legislation requires that the ISO use standards no less strict than that of the WSCC. There are several criteria that the WSCC applies to reserves (WSCC, 1995), including the requirement that generation capacity up to 5% of demand served by hydro generation and 7% of demand served by non-hydro generation be available as spinning reserve. Since the pool of potential suppliers of spinning reserve is essentially the same as that of energy, we account for these reliability requirements by escalating the demand level for which generation must be supplied by 6% in each of the hours we modeled.[26]

The demand forecasts that we work from are for peak hours in each month. We assume that the *shape* of the load curve will be approximately the same as it currently is, and from that assumption, we derive expected loads at lower-demand hours. For instance, if the 150th highest load hour in June were currently 70% of the peak demand, we assume that the 150th highest load hour in June 2001 will be 70% of the June 2001 peak load (for

even approached $2000/MWh in one instance, with little significant impact on demand (See Wolak and Patrick, 1996).

[25] While this figure is necessarily a very rough estimate, the results of this study are not very sensitive to its magnitude, since it affects the perceived cost of all competitors equally.

[26] In practice, during its first year of operation, the ISO has been purchasing far more than the WSCC required reserves. The use of reserves is currently under review, however, and expected to be reduced by 2001.

which we have a forecast). This determines a quantity for the “anchor point” for the assumed demand curve in 150th highest demand hour. The price for the “anchor point” was 9.3¢/kwh in all cases. Once an anchor point for the assumed demand curve was established, we constructed a constant-elasticity demand function that included this point and had the assumed elasticity (0.1, 0.4, or 1.0). Note that the 9.3¢/kwh figure is used only to scale the demand *functions* at different load hours. It is not an estimate of the resulting equilibrium price in any given hour, just the price point at which quantity is shifted according to the current load ratios in order to yield different demand functions at different hours. Within each simulation, demand elasticity was always assumed to be the same in all hours.

In examining the aggregate demand for electricity in the state, we assume that there will be no significant price discrimination between customer classes. In other words, there will be no price differences between classes other than those based on the relative cost of serving each customer class. The likely presence of marketers and other entities who would be able to arbitrage any artificial price differences between customers and markets would eliminate the ability of suppliers to price discriminate between customer classes.

Pre-existing Contractual Arrangements

With the exception of independent power producers that are described above, we do not include consideration of existing contractual agreements between utilities. If both markets are implemented efficiently, the market for "physical" long-term power contracts and spot energy should not be very distinct from each-other. Significant price differences between markets will prompt adjustments from the other. Most existing purchase agreements between electric utilities are not of the "take-or-pay" variety. Therefore these contracts are not expected to produce the distortions experienced in the natural gas industry.

3.4 Cournot Algorithm

Using the marginal cost functions of the Cournot competitors and a residual demand function, which is the market demand minus the fringe supply at every given price, we calculate the Cournot equilibrium iteratively. Using a grid-search method, we determine the profit-maximizing output for each supplier under the assumption that the production of the other Cournot suppliers is fixed. This is repeated for each Cournot firm: the first supplier sets output under the assumption that the other Cournot players will have no output, the second sets output assuming the first will maintain its output at the level that was calculated for it in the previous iteration, and so on. The process repeats, returning to each supplier with each resetting its output levels based upon the most recent output decisions of the others, until no supplier can profit from changing its output levels given the output of the other Cournot suppliers. Thus, at the Cournot equilibrium, each firm is producing its profit-maximizing quantity given the quantities that are being produced by all other Cournot participants in the market.

It is worth noting that although a constant elasticity demand curve with elasticity less than one would cause a monopolist to charge an infinite price, no one firm faces that demand curve. Each Cournot player faces a demand function that is the residual demand curve in equation (1) above minus the quantities being produced by all other Cournot players. Firm *i*, which is a Cournot player, faces demand

$$D_i(P) = D_r(P) - \sum_{j \neq i} D_j \qquad \textbf{(2)}$$

where *j* indexes firms that are Cournot players and $D_r(P)$ is the residual demand curve defined in (1). This demand will in general be much more elastic than *D(P)* at every price.[27]

One drawback of our treatment of the price-taking fringe is that the residual demand, being *D*(*P*) minus the fringe supply, can have flat regions in it. This results from the fact that each plant is assumed to have a constant marginal cost up to capacity, causing the fringe supply curve to have flat regions. As a result, the demand curve faced by any one firm will also have flat regions and those flat regions will be associated with discontinuities in the marginal revenue curve that the firm faces. For a given firm, this can result in multiple local profit maxima. This in itself is not a problem since our grid-search method assures that the output derived is a firm's global profit maximum. However, this can also lead to multiple equilibria since small changes in the output of other firms can cause a given firm to make relatively large jumps in its own output. In the few instances in which multiple equilibria were found in our simulations, however, one of the equilibria always Pareto dominated all others (from the perspective of the firms). We selected the Pareto dominant equilibrium for inclusion in our analysis.

4. Results

We examine several scenarios representing different assumptions and issues concerning the organization of the electricity market. We calculate the Cournot equilibria at several demand levels for four months of the year, March, June, September and December. These months were selected to account for seasonal variations in available hydro energy, relative regional demand levels, and gas prices. For each month we calculate the Cournot equilibrium price for 6 representative hours: the peak demand hour and the hours with the 150th, 300th, 450th, 600th, and 744th[28] highest demands of the month. As a benchmark equilibrium, we also calculate the price that would result if all firms acted as competitive price takers.

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[27] Although a constant-elasticity demand function with elasticity less than one would yield an infinite price for a monopolist, equilibrium price will always be finite if there is positive output from a price taking fringe. To see that this is the case, note that with positive output from the price taking fringe, the residual demand faced by Cournot firms in a market will, at a sufficiently high price, always intersect the vertical axis.

[28] March and December have 31 days or 744 hours. June and September have 30 days, so the bottom category is the 720th hour for these months.

The scenarios we model include a base case that reflects the status quo, as of 1997, in the ownership and capacity of resources, and two possible sets of divestitures of gas-fired capacity by PG&E and SCE. Our scenarios also assume that existing QFs continue to provide power on a must-take basis.

We model the base case using price elasticities of demand equal to 0.1, 0.4, and 1.0. The results of these simulations are presented in detail in the Appendix A. Figures 3-5 summarize the Cournot equilibrium and competitive market price for the selected hours of each month that were simulated. In relatively low demand hours, such as the off-peak hours in June, September, and December, and all of March, Cournot and competitive equilibrium prices are very similar regardless of the demand elasticity assumed. (Note that the scales in figure 3 and later figures differ across months.) However, the Cournot equilibrium price in certain peak hours, such as the three highest demand levels we analyze in September were very sensitive to the demand elasticity. These hours reflect demand levels for which most of the competitive fringe is supplying at or near its capacity, meaning that the price-sensitivity of demand plays a relatively greater role in determining the degree to which the Cournot price will deviate from the competitive level.

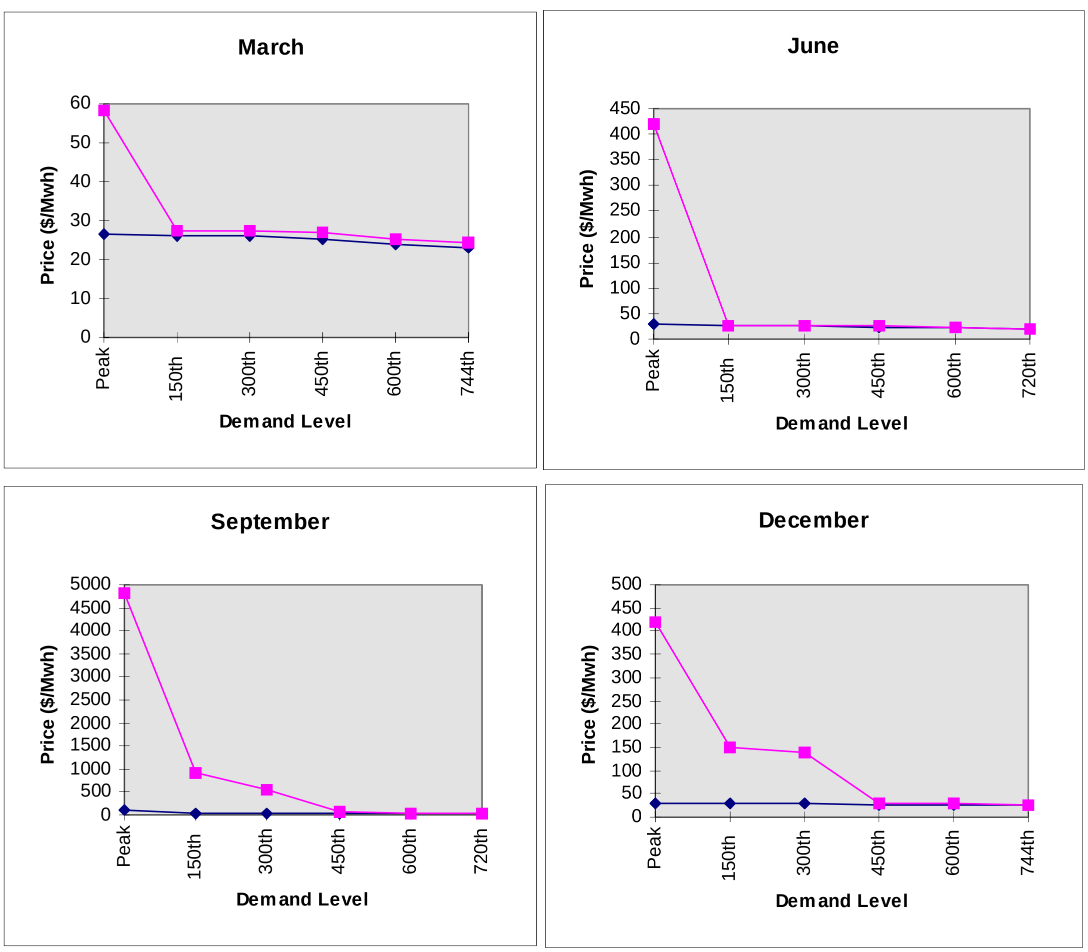

Figure 3: Market outcomes for base case with elasticity = 0.1

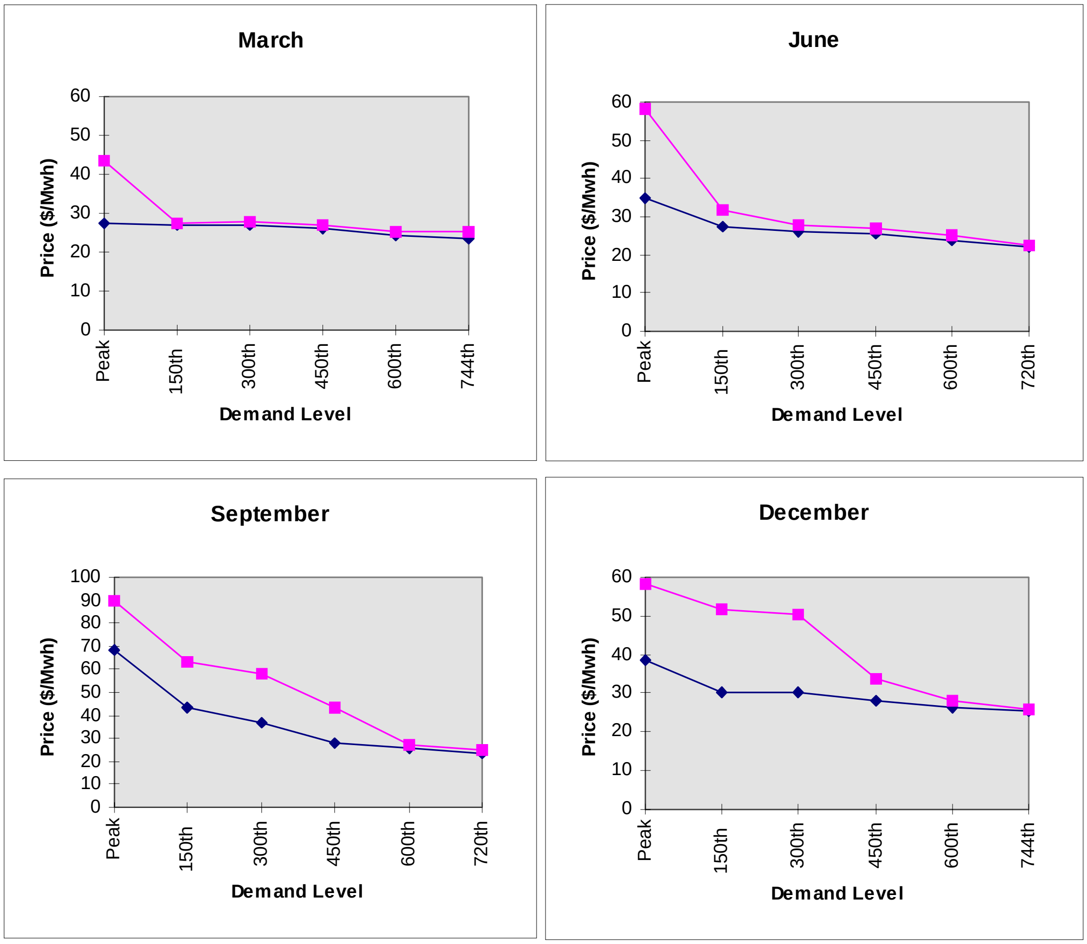

Figure 4: Market outcomes for base case with elasticity = 0.4

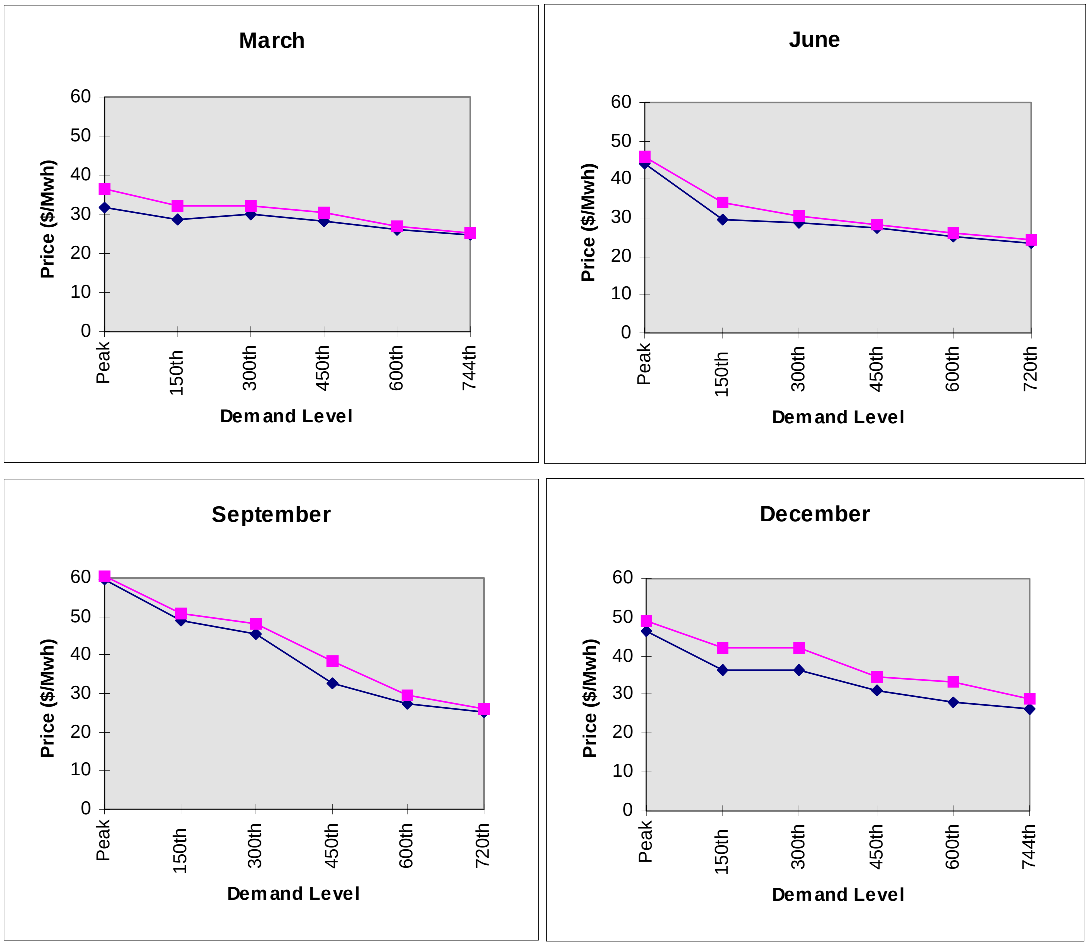

Figure 5: Market outcomes for base case with elasticity = 1.0

The Cournot equilibrium price for the modeled demand hours for each of the three demand elasticity levels examined are presented in Tables 9-11 of Appendix A. The reader may note that in many hours the Cournot equilibrium price is *increasing* with demand elasticity rather than decreasing. In fact, the competitive market price also rises with the assumed elasticity. This results from the fact that all demand functions are "anchored" at the forecast demand levels given an assumed price of 9.3¢/kwh (including distribution costs), *i.e.*, demand functions for a given month, but different assumed elasticities, all cross at that price. At any lower price, a more elastic demand curve will therefore be to the right of the less elastic demand curve, as illustrated in figure 6. For sufficiently high prices, those above the "anchor" price, less elastic demand is associated with higher Cournot and competitive equilibrium prices.

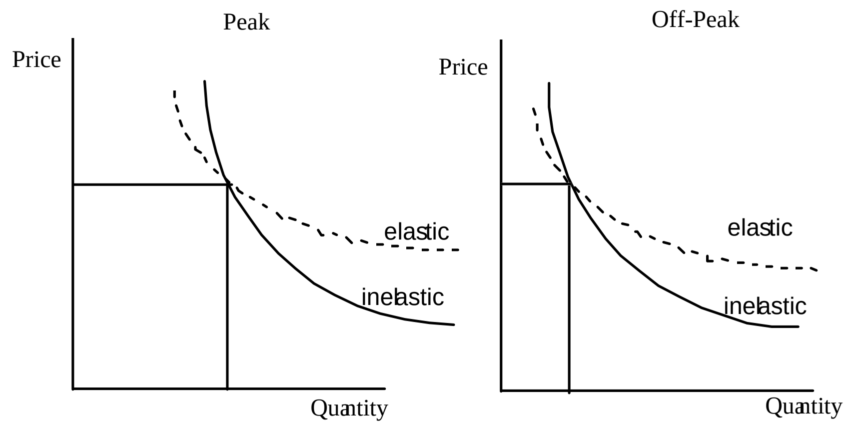

Figure 6: Effect of Elasticity on Relative Position of Demand Functions

To analyze the exercise of market power, it is perhaps most useful to examine the "industry Lerner index" that obtains in the Cournot equilibrium. We define the industry Lerner index as, *(P-c)/P*, where *c* is the industry marginal cost at the Cournot quantity if that quantity were produced at least cost by the industry, *i.e.*, the marginal cost if all firms were price takers and the industry produced the Cournot quantity. This is the markup over the price that would yield the same output in a perfectly competitive market. These values are presented in Table 4 for the months with the least and most market power.

Table 4: Industry-wide Lerner index for the base case

Demand Level	**Industry-wide Lerner index at Cournot Equilibrium (%)**					
	March			**September**		
	0.1	**0.4**	**1.0**	**0.1**	**0.4**	**1.0**
Peak	55	41	22	99	64	15
150th highest	6	1	12	97	52	33
300th highest	6	4	10	95	50	29
450th highest	7	5	8	59	46	26
600th highest	5	4	4	4	7	10
720/744th highest	5	4	6	5	3	7

The RelationshipBetween Market Power and Concentration

An examination of hourly output levels also reveals some of the shortcomings of concentration measures. To illustrate this, Table 5 shows the firm-by-firm output for the month of December in the base case run with demand elasticity equal to 0.1.[29] [30]

[29] Firm-by-firm production results from all the simulations summarized in appendix A are available for downloading from the Energy Institutes Website. The address and filename are www-ucenergy.eecs.berkeley.edy/ucenergy/PDF/pwp044R_output.pdf.

[30] It is interesting to note that in the three highest demand hours of December the transmission path from the southwest is constrained. In these hours, the coal units owned by SCE that are located in the southwest would earn the lower southwest price rather than California spot price. We assume that SCE's generation

Table 5: Simulation results for December of the base case - elasticity = .1

Demand Level		**Peak**	**150th highest**	**300th highest**	**450 th highest**	**600th highest**	**744th highest**
Competitive Price ($/MWh)		34.01	28.73	28.82	26.98	25.76	25.16
Price ($/MWh)		421.22	150.88	137.58	28.13	28.06	25.42
Mkt Quantity MW		37454	35703	33960	32661	28113	24380
PGE	*Fossil* (MW)*	2218	1361	1160	4679	2693	1794
	Nuclear (MW)	1901	1901	1901	1901	1901	1901
	Pondage hydro	999	999	999	999	999	999
	Total Quantity	5118	4261	4060	7579	5593	4694
SCE	*Fossil* (MW)*	4296	3433	3231	5851	2339	2293
	Nuclear (MW)	1955	1955	1955	1955	1955	1955
	Pondage hydro	294	294	294	294	294	294
	Total Quantity	6545	5682	5480	8100	4588	4542
LADWP	*Fossil* (MW)*	5759	5759	4512	3768	3768	1804
	Nuclear (MW)	340	340	340	340	340	340
	Pondage hydro	39	39	39	39	39	39
	Total Quantity	6138	6138	4891	4147	4147	2183
SDGE	*Fossil*	1875	1829	1736	667	363	0
	Nuclear	378	378	378	378	378	378
	Total Quantity	2253	2207	2114	1045	741	378
Cal Fringe**	*Pondage Hydro*	973	973	973	973	973	973
	Total Quantity (MW)	11004	10971	10971	9351	9419	8654
NW Fringe	*Total Quantity (MW)*	0	0	0	0	0	0
SW Fringe	*Total Quantity (MW)*	6056	6056	6056	2439	3625	3861
Mexico Fringe	*Total Quantity (MW)*	340	388	388	0	0	68

* Includes pumped storage and geothermal ** Includes IPP must take capacity and hydro output
NOTE: Cournot quantity choices of PG&E, SCE, and SDG&E include only fossil and hydro production.

Note that the three highest demand hours modeled produce significant price-markups. The Cournot equilibrium price in the next highest demand hour modeled, the 450th highest for the month, is by comparison only marginally above the perfectly competitive price for that hour. Figure 7 shows the HHI for each of these hours[31] along with the

company would not own the transmission rights along this path. As explained above, these units would not be considered infra-marginal by SCE on when it makes its output decisions for the California market.

[31] The Hirschman-Herfindahl Index (HHI) is the sum of the square of each firm's market share times 10,000. For Cournot firms, market share was defined as total company output divided by market output.

markup over competitive price resulting from the Cournot simulation. The HHI and markup do not exhibit any systematic correlation.

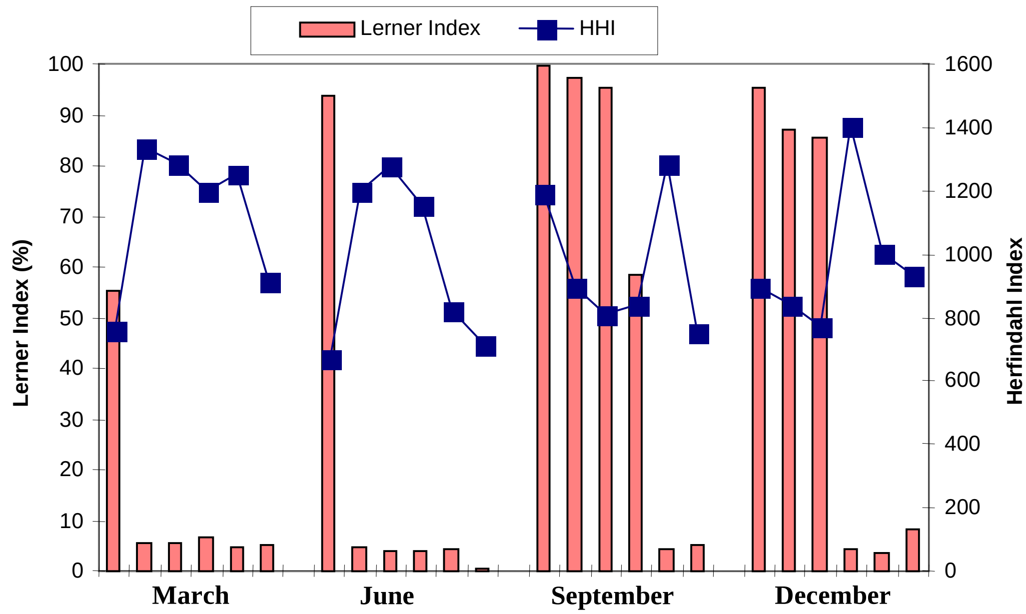

Figure 7: The Herfindahl Index versus the Lerner Index

The price differences are largely driven by the elasticity of fringe supply. In the peak hours the Cournot firms reduce their output and fringe firms utilize nearly all of their capacity, or in the case of the southwest fringe, all the available transmission capacity. The economic capacity belonging to fringe firms is exhausted, allowing the Cournot firms to significantly increase price by reducing output. The production levels of the Cournot firms in response to the level of demand relative to fringe capacity is further illustrated in Figure 8. This chart illustrates the aggregate production levels of the three Cournot firms when they are all acting strategically and also under perfect competition.[32] When these firms act strategically, the reduction of output is significant in peak hours, which is when demand is high enough that the fringe is unable to make up the shortfall. In lower demand hours, fringe production is the marginal output, and the Cournot firms have much less incentive to withhold production.[33]

To estimate the market shares of fringe firms, we divided the fringe output by the number of firms present in each fringe grouping. Note that in Table 5, LADWP is treated as its own fringe grouping.

[32] It is important to note that the production levels illustrated in Figure includes hydro output, which was scheduled outside of the Cournot algorithm. The bulk of this output was concentrated in peak demand hours.

[33] Put slightly differently, when the fringe is producing in a region in which its supply is rather price elastic, the residual demand that the Cournot firms face is also rather price elastic. When the fringe is producing near its capacity, its supply is price inelastic, and likewise the demand faced by the Cournot firms is also less elastic. Thus, the Cournot firms may have incentive to produce lower output as total demand increases.

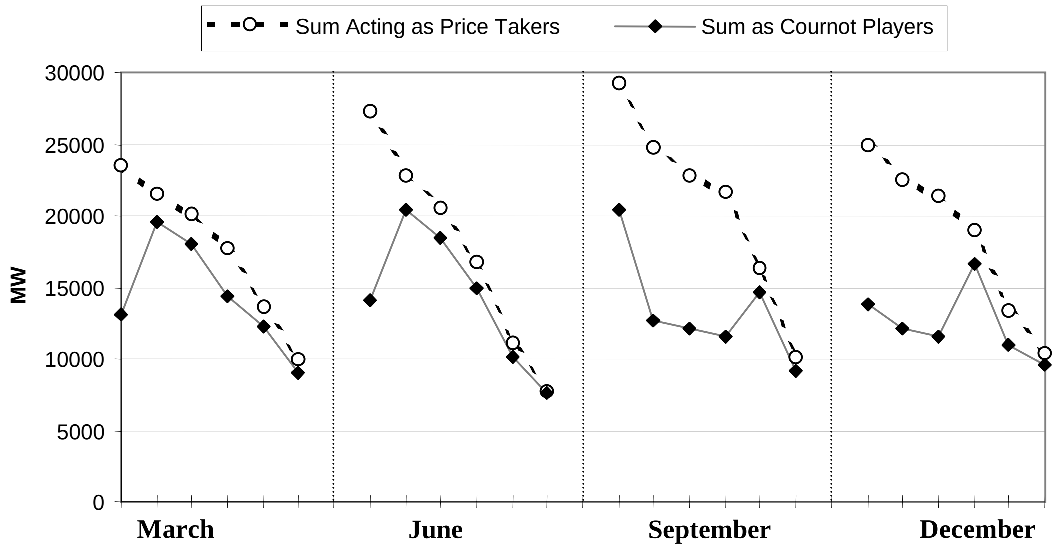

Figure 8: Production levels of the Cournot firms

4.1 Divestiture of gas-fired generation

In response to market power concerns, SCE filed a plan in 1996 to divest all of its gas-fired generation in four roughly equal size lots. SCE proposed that no single firm be allowed to buy more than 2 of the 4 generation sets. At about the same time, PG&E proposed the divestiture of roughly half of its gas-fired capacity. Buyers and prices for most of these units have now been identified, and transfer of ownership is scheduled to occur before 2001. Very recently, in 1998, PG&E has announced plans to divest all of its thermal generation.

We examine two possible divestiture options. The first option spins off all of SCE's gas units and half of PG&E's into three firms, one firm owning 1/2 of the PG&E gas units and two firms each owning two of the four sets of SCE's gas units. We assume that these new firms (in addition to the incumbent IOUs) act as Cournot players. This option is labeled 'partial divest' in the tables below. The second option represents generation ownership according to the most recently announced proposal and sales of units. This new ownership pattern divides the gas-fired PG&E and SCE resources amongst seven firms. This option is referred to as 'full divest' in the tables below. The effect of each of these divestiture options for September on the Cournot equilibrium price is shown in Table 6.

Table 6: Effects of divestiture options on equilibrium price

Demand Level	September Energy Price at Cournot Equilibrium ($/MWh)							
	Demand Elasticity = 0.1				Demand Elasticity = 0.4			
	Perfect Comp.	No Divest	Partial Divest	Full Divest	Perfect Comp.	No Divest	Partial Divest	Full Divest
Peak	**124.88**	**4829.24**	**427.83**	**186.13**	**68.62**	**89.60**	**69.34**	**69.34**
150th highest	**33.93**	**932.18**	**159.13**	**58.17**	**43.44**	**63.08**	**52.36**	**46.27**
300th highest	**32.09**	**555.08**	**121.20**	**58.17**	**36.71**	**58.17**	**46.72**	**41.34**
450th highest	**26.78**	**63.08**	**28.05**	**28.05**	**28.20**	**43.31**	**31.55**	**28.19**
600th highest	**24.37**	**25.42**	**25.18**	**25.18**	**25.43**	**27.00**	**25.42**	**25.42**
720/744 highest	**22.96**	**24.20**	**23.87**	**23.74**	**23.56**	**25.18**	**24.2**	**24.2**

The change in peak price in comparison to the base case is substantial, even when the units are only partially divested to Cournot firms. For an elasticity of 0.1, prices in the peak demand hour of September dropped 91% under the partial divestiture scenario and 96% under ‘full’ divestiture. Once again, the benefits of more price responsive demand are apparent, as peak prices are 5 to 6 times higher when demand elasticity is 0.1 than when it is 0.4. Of course, divestiture to smaller firms may eliminate some scale economies of multi-plant operation (no such economies are assumed here). If these economies are not very large, we would expect prices to be likely to be lower if divested plants are sold to many different firms.

Table 7 shows the effects of the partial divestiture scenario on consumer surplus and deadweight loss for the peak month of September. During the peak hour of this month, partial divestiture with a demand elasticity of 0.1 increases consumer surplus by about $183.6 million compared to the base case, of which about $165.9 million is a transfer from producers and the remaining $17.7 million is a reduction in deadweight loss.

Table 7: Consumer Surplus and Deadweight Loss – September

Demand Level	Consumer surplus loss (relative to perfect competition) and deadweight loss (Millions $/hr)							
	Demand Elasticity = 0.1				Demand Elasticity = 0.4			
	Consumer Surplus loss - Base	Consumer Surp loss - Partial Div	DW loss - Base	DW loss – Partial Divest	Consumer Surplus loss - Base	Consumer Surp. loss Partial Div	DW loss - Base	DW loss - Partial Divest
Peak	**198.998**	**15.447**	**18.885**	**1.186**	**1.174**	**.041**	**.259**	**.003**
150th highest	**34.288**	**5.386**	**2.807**	**.297**	**.874**	**.400**	**.099**	**.027**
300th highest	**18.970**	**3.548**	**1.452**	**.201**	**.877**	**.412**	**.063**	**.009**
450th highest	**3.852**	**.046**	**.237**	**.002**	**.739**	**.121**	**.036**	**.000**
600th highest	**.032**	**.025**	**.002**	**.000**	**.048**	**.000**	**.001**	**.001**
720/744 highest	**.033**	**.024**	**.000**	**.000**	**.043**	**.017**	**.001**	**.001**

4.4 Transmission flows within California

The results presented up to this point assume that there are no binding transmission constraints inside of California that would create geographic sub-markets within the State. The major transmission path constraint in California is the Path 15 constraint separating northern and southern California. Pacific Gas & Electric has both customers and generators on both sides of this transmission path. For our Cournot divestiture case, assuming an elasticity of 0.1, we calculate the supply and demand in the northern and southern California regions. We can estimate the net flow over the Path 15 demarcation, in the absence of a binding constraint on that path, to be the difference between supply and demand between regions. We also recognize that flows from the northwest region into each part of California could be reallocated to relieve possible congestion of Path 15. The results of this calculation are illustrated in Figure 9 for the partial divestiture case.

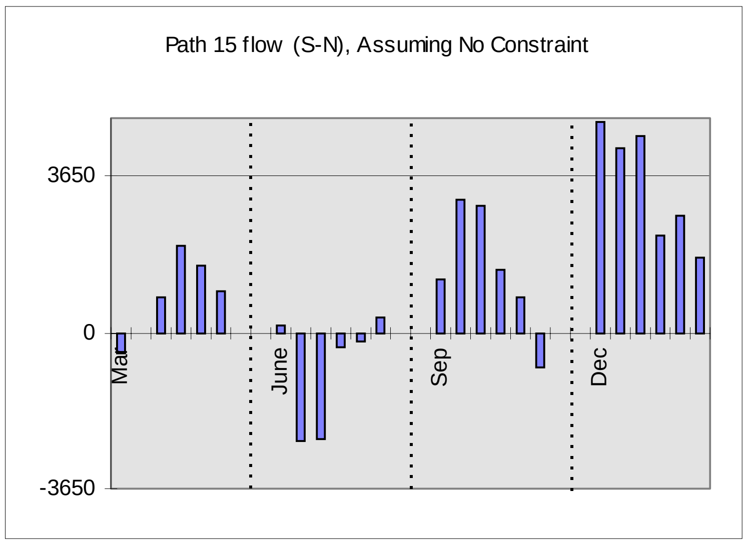

Figure 9: Flows over Path 15 assuming no constraint - partial divestiture

(Path Capacity is 3650 MW)

It is crucial to understand that the flows that would result from a Cournot equilibrium where the competitors assume there will be no in-state congestion (as is shown in Figure 10) are not the same as the potential congestion that would arise if strategic players explicitly account for potential in-state congestion in their output decisions.[34] A Cournot player in a specific region, knowing that potential imports into that region would be limited by transmission constraints, may very well reduce its output below the level of output it would choose if there were no limits on transmission capacity. We now examine this behavior when in-state producers explicitly account for the Path 15 constraint.

[34] Borenstein et.al. (1997) present a thorough analysis of the incentives of a firm to induce congestion of a transmission line into its region and then optimize along the resulting residual demand function.

The constraint of concern is south-to-north flow over the Path 15 demarcation. The actual flow limits over this path vary with supply and load conditions, but we use an estimate of 3650 MW for the maximum flows over this path. This is roughly the midpoint of the range identified by Pace (1996). In periods when there is little hydro energy available, both northern California and the Pacific northwest import power from the south. Thus, the periods in which the flows over Path 15 may reach their limits are likely to coincide with periods in which their is very little competitive generation available for export in the Pacific northwest. We examine the northern California market for the months of September and December under the assumption that the flows to the north over Path 15 were at their maximum. To determine whether this congestion would in fact arise, we compared the operating profits of the dominant firm (in this case PG&E) under the assumption of no Path 15 congestion with the profits of that firm if it chose to restrict its own output to the point that the path is congested.

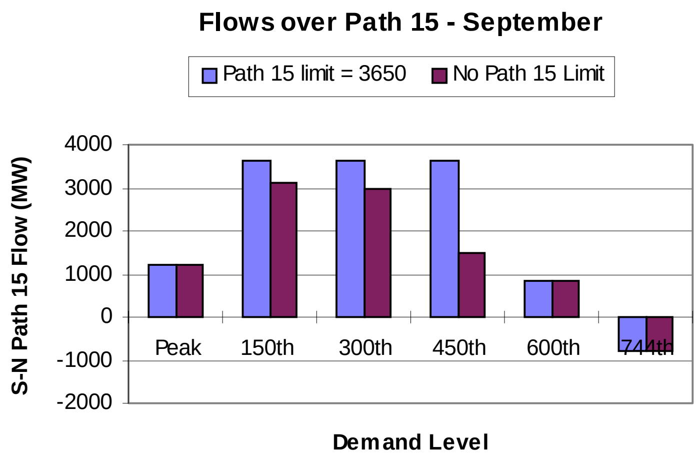

Figure 10: Strategic Effects of Path 15 Constraints - Partial Divestiture

From these results, we find that the dominant firm in the north would prefer to reduce output and congest Path 15 in three of the six hours we examine of September.[35] Note that if PG&E was not taking the Path 15 constraint explicitly into consideration, Path 15 flows would not exceed its limit in any hour of September. Thus PG&E, knowing that competitive capacity will be limited by the Path 15 constraint, would find it more profitable to reduce output further and congest that path. In several of the highest demand hours of this month, demand cannot be met by the combined capacity of northern California municipal utilities, QFs and the divested PG&E units, which we call PGE2, even after accounting for imports of 3650 MW over Path 15.

This comparison still is not sufficient to determine conclusively whether the Path 15 constraint would be binding when it is incorporated into a firm's output decision. The profit comparison for PG&E indicates when PG&E would want the path to be congested, but we need to determine whether PGE2 would also profit from this congestion. To test

[35] This is also the case for all but the most off-peak demand hour in December.

whether the outputs yielding a congested link were indeed an equilibrium, we held PG&E's output level constant at its congestion-inducing level and tested whether PGE2 would prefer to increase its output to a level that would relieve the congestion on Path 15. In every case PGE2 either reaped greater profits from playing along with the congestion strategy than from unilaterally relieving the congestion, or did not have sufficient capacity to relieve the congestion on its own.

Even though both of the northern strategic firms prefer Path 15 to be congested in these hours, it still remains to be determined whether California firms in the south would be willing to congest it. To do this, we examine the southern California market under the assumption that there will be an aggregate outflow of 3650 MW over Path 15 to northern California. This was accomplished by adding 3650 MW to the native demand in the south. In order for there to be congestion on Path 15 in equilibrium, we must find that the price in southern California is lower than the price in northern California.[36] As Table 8 indicates, this is indeed the case for the hours in which PG&E and PGE2 find it profitable to reduce output and congest Path 15. Note that in several hours prices in *both* northern and southern California are higher than they would have been if the Path 15 constraint did not exist.

Table 8: Price Impacts of Path 15 Congestion – Partial Divestiture

Demand Level	**Peak**	**150th highest**	**300th highest**	**450th highest**	**600th highest**	**744th highest**
<u>September</u>						
(with path limit = 3650 MW)						
North Cal. Equilibrium Price ($/MWh)	427.83	931.36	410.07	125.79	25.18	24.2
South Cal. Equilibrium Price ($/MWh)	427.83	305.95	234.83	58.35	25.18	24.2
Path 15 Flows (South to North)	1211	3650	3650	3650	833	-1571
(with no path limit)						
North/South Cal. Equilibrium Price ($/MWh)	427.83	159.13	121.2	25.05	25.18	24.2
Path 15 Flows (South to North)	1211	3115	2968	1479	834	-1571

An examination of the same comparisons when demand elasticity is 0.4 indicates that congestion over this path is reduced when demand is more price responsive. Profits for PG&E are greater in every hour of September when flows over Path 15 are not at their maximum, indicating that PG&E would prefer to not congest the path in those hours. The Path 15 constraint, however, is still binding in most hours of December.

[36] It is important to note that our representation of the transmission grid is a radial network of the lines connecting California with its neighboring States. In a meshed network, one might see price differences between regions even though the lines connecting those regions are not congested. Further, it is possible in a meshed network that, along a congested path, power may flow from a high cost region to a lower cost region (See Wu, et al., 1996).

4.5 Sensitivity of Results to Hydroelectric Production

The results presented in previous sections assume that the hydro energy available in each month modeled is equal to the average (for that month) of the actual production over the 1992-95 period. There is, however, significant variation in hydro production from year to year. To investigate the impact of varying water levels on market power, we also calculate the Cournot equilibrium for the base case and the partial divestiture case using the actual hydro levels during 1995-1996.[37] Hydro-electric production in 1995-96 was significantly higher than the four year average. These results are shown in Appendix C.

In several of the hours we analyzed in December, the increased hydro output lowered base case prices to approximately the same levels produced by the partial divestitures under the average hydro conditions. Most of these benefits arise from the additional competitive resources in the Pacific northwest that are available for export into California. These results indicate that the frequency and severity of market power will be significantly muted in years of above average hydro conditions.

4.6 Intertemporal Scheduling Issues

As we have noted above, two issues of intertemporal generation scheduling are not fully incorporated into this study. First, the scheduling of hydro production is assumed to simply shave peaks in quantity demanded rather than fully maximize profits by equalizing the producer's marginal revenue of hydro production across periods. To explore the sensitivity of our results to this treatment of hydro, we investigated one scenario in more detail. For the partial divestiture scenario with a demand elasticity of 0.4 in the month of September, we attempted to iteratively reallocate PG&E's hydro production to equalize its marginal revenue across periods.

The results indicate that, at least in this one case, the optimal hydro scheduling involves significantly different allocation of hydro production than is implied by the peak-shaving algorithm. The equilibrium prices, however, are very little changed by this reallocation of hydro. As PG&E's hydro is moved out of one period, for instance, the market price rises and substantial output from other large producers and the competitive fringe results. Thus, although, a more sophisticated treatment of hydro scheduling is likely to yield more accurate predictions of hydro use, and could significantly affect the forecasts of hydro production, it may not have much effect on the forecasts of price/marginal cost differences.

There is also the likelihood that hydro energy provided by the fringe will shift from off-peak hours to higher demand hours in response to the higher prices resulting in those hours in the Cournot equilibria. This would reduce the market power effect in those hours. We note, however, that market power is most severe when there is little spare hydro energy available from the northwest, so the impact of this effect may not be

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[37] The figures used were actual hydro-electric production in the months of December, 1995, and March, June, and September 1996.

significant. The dynamic interaction of both strategic and fringe hydro producers is an important topic for future study.

The second intertemporal scheduling issue that is not incorporated in this analysis is unit commitment. In modeling each hour independently of the others, we do not account for the various intertemporal constraints on thermal units such as start-up costs, minimum up and down times, and ramping rates. These constraints are an important extension of oligopoly models in the electricity industry that merits further study. Even from our analysis, however, we can draw some qualitative conclusions here about the effects of such constraints.

In general, the linking of adjacent hours in the output decisions of Cournot players will tend to reduce their output further in peak hours while increasing in the off-peak hours. In setting output levels in peak hours, firms will have to consider the possibility that certain units deployed for those peak hours could not be shut down in intervening off-peak hours. Thus, that firm may choose not to operate any units with marginal costs near the firm's marginal revenue in the absence of intertemporal constraints. Similarly, some units for which intertemporal constraints are binding will still be operated on-peak. Those units would have to be operated at some level in off-peak hours, effectively lowering firm's marginal costs in those hours and increasing output over the levels indicated when intertemporal constraints are not considered.

4.7 Integrated Regional Markets

The results presented above have focused on the California electricity market. Markets in the regions outside of California have been considered only to the extent of their ability to export power *into* California. As such, we do not examine the impact of exports *from* producers in California. In general, we expect that including the possibilities of exports from California would increase California prices at least in some hours, since this would (weakly) raise the marginal cost of production in the state.

There are several other aspects of the integrated regional market that deserve further analysis. When we examine Path 15 flows, we account only for exports out of southern California into northern California. In addition it is common for power to flow from the southern California to the Pacific northwest in low hydro months. Explicitly accounting for these exports may add additional congestion over this path. We also schedule the hydro resources in each region according only to that region's demand profile. When the demand, and market prices, of combined regions is considered, we would expect the hydro allocations to differ somewhat. To the extent that we treated all out-of-state hydro resources as fringe suppliers, any adjustments to market outcomes inside California would serve to reduce the impact of market power. Once again, it is difficult to estimate the impact of such a response without modeling the combined markets.

5. Conclusions

Absent significant divestiture of assets by incumbent producers, the restructured California electricity generation market could have a few large producers each of which would potentially find it profitable to restrict output to raise price. Previous attempts to estimate the risk of market power have relied on concentration measures. These measures fail to account for demand or supply elasticities in the market. They are a rough approximation that are best used only when better data are not available. In this case, better data are available. We use historical data on plant costs and capacities to simulate the competitive market for electricity following restructuring. The simulation recognizes that large firms might have an incentive to restrict output to raise price. We are able explicitly to analyze each firm’s incentive to do this.

While the approach that we employ accounts for demand and supply elasticities and for the incentive of firms to restrict output, it does not explicitly consider the effects of market entry and exit. We suggest that these considerations – as well as recognition that consumers are able to adjust to prices more completely over longer periods – argue for consideration of simulations using demand functions that are more price-elastic than most short-run estimates. Otherwise, the model is likely to forecast greater exercise of market power than will actually occur. Our approach also does not account for the possibility that firms engaged in repeated interactions with one another may compete less aggressively over time. This could cause the model to forecast less exercise of market power than will actually occur. Unfortunately, economic models of such dynamic interaction are notoriously complex and the results usually indeterminate, offering virtually no guidance for empirical implementation.

The Cournot analysis allows us to examine a broad range of potential strategic actions. However, it is a stylized representation of both the costs and range of strategies available to firms. The results should therefore be thought of as a screening for the potential for market power, and an indication of the ways market power might be exercised, rather than an exact forecast or prediction of market prices. As a screening tool, the Cournot analysis presents several advantages over concentration measures. In particular, it can explicitly test for whether an individual firm can profit from a unilateral reduction in output. Of course, to be a useful screening tool such analysis must incorporate the actual physical, institutional, and regulatory constraints under which the market operates.

We simulate the California market in the year 2001, because it is probably the earliest date at which the market will not be significantly distorted by transition charges and guaranteed prices. The Cournot model indicates that, under the historical industry structure, there is the potential for market power in the high demand hours of several months of the year. Divestiture of SCE and PG&E thermal plants would substantially lessen market power, we find. Perhaps the greatest impact on the severity of market power comes from increased price responsiveness in the market. In the hours in which the potential for market power exists, its impact on prices is significantly reduced when the elasticity of demand is increased from the current short-run estimates of around 0.1. It is important for policy makers to recognize that elasticities of both supply and demand are not exogenous variables. Our results indicate that policies that promote the responsiveness of both consumers and producers of electricity to short-run price fluctuations can have a significant effect on reducing the market power problem. Such policies may be more rewarding, and less contentious, than other approaches that attempt to regulate prices under various conditions.[38] An alternative or complementary approach to limit market power could be the expansion of transmission paths between California and neighboring areas. Greater integration between California and neighboring markets would reduce the incentive of any one producer to restrict output in order to raise price. In some cases, this could be a cost-effective response to the threat of market power, but costs of transmission capacity upgrades vary widely.[39]

While our finding of some potential for market power makes deregulation of generation less attractive than if there were no possibility of market power, this finding should not be seen as suggesting that deregulation is a mistake. Very few markets are completely devoid of market power. One must compare the prices consumers will face in a deregulated market with the outcome under an alternative, such as continuation of the pre-deregulation regime. We have not attempted to forecast prices under continued regulation or to make such a comparison.

[38] It is important, of course, that demand elasticity be incorporated in formation of the market price. That is, the market-clearing price must be based on both price-responsive supply bids and price-responsive demand bids. If the market is operated with only a fixed estimate of quantity that will be demanded, much of the market-power mitigation from elastic demand is lost.

[39] See Baldick and Kahn (1993).

Appendix A - Simulation Results

Table 9: Market outcomes for base case with elasticity = 0.1

Demand Level	**Peak**	**150th highest**	**300th highest**	**450th highest**	**600th highest**	**744th highest**
March						
Competitive Price ($/MWh)	26.69	25.95	25.95	25.25	23.97	22.96
Cournot Equilibrium Price ($/MWh)	58.35	27.45	27.45	27	25.18	24.2
Market Quantity	40092	38966	36638	31242	26397	23425
June						
Competitive Price ($/MWh)	30.44	26.18	25.23	24.41	23.16	20.84
Cournot Equilibrium Price ($/MWh)	419.95	27.45	26.24	25.42	24.2	20.83
Market Quantity	44743	42693	37758	32082	27078	22003
September						
Competitive Price ($/MWh)	124.88	33.93	32.09	26.78	24.37	22.96
Cournot Equilibrium Price ($/MWh)	4829.2	932.17	555.08	63.08	25.42	24.2
Market Quantity	39047	35206	33737	34749	30327	26342
December						
Competitive Price ($/MWh)	34.01	28.73	28.82	26.98	25.76	25.16
Cournot Equilibrium Price ($/MWh)	421.22	150.88	137.58	28.13	28.06	25.42
Market Quantity	37454	35703	33960	32661	28113	24380

Table 10: Market outcomes for base case with elasticity = 0.4

Demand Level	**Peak**	**150th highest**	**300th highest**	**450th highest**	**600th highest**	**744th highest**
March						
Competitive Price ($/MWh)	27.5	27.06	27.01	26.18	24.37	23.47
Cournot Equilibrium Price ($/MWh)	43.52	27.46	27.9	27	25.42	25.18
Market Quantity	42089	42904	40236	34471	29324	26022
June						
Competitive Price ($/MWh)	34.74	27.3	26.18	25.43	23.89	22.18
Cournot Equilibrium Price ($/MWh)	58.17	31.55	27.9	27	25.18	22.46
Market Quantity	51375	45917	41394	35313	30079	24729
September						
Competitive Price ($/MWh)	68.62	43.44	36.71	28.19	25.43	23.56
Cournot Equilibrium Price ($/MWh)	89.6	63.08	58.17	43.31	27	25.18
Market Quantity	50236	42725	39749	33085	33382	29263
December						
Competitive Price ($/MWh)	38.49	30.25	30.42	28.19	26.18	25.43
Cournot Equilibrium Price ($/MWh)	58.35	51.58	50.31	33.94	28.13	25.99
Market Quantity	42986	38602	36657	34703	30861	27000

Table 11: Market outcomes for base case with elasticity = 1.0

Demand Level	Peak	150th highest	300th highest	450th highest	600th highest	744th highest
March						
Competitive Price ($/MWh)	31.64	28.91	29.88	28.19	26.18	24.7
Cournot Equilibrium Price ($/MWh)	36.35	32.07	32.07	30.34	27	25.42
Market Quantity	49110	48691	45783	39972	35361	32089
June						
Competitive Price ($/MWh)	44	29.75	28.69	27.46	25.25	23.47
Cournot Equilibrium Price ($/MWh)	45.97	33.85	30.54	28.17	26.15	24.3
Market Quantity	56792	52065	48120	42254	36684	30501
September						
Competitive Price ($/MWh)	59.77	48.8	45.5	32.84	27.3	24.96
Cournot Equilibrium Price ($/MWh)	60.55	50.72	47.9	38.2	29.72	26.15
Market Quantity	53060	45638	42975	41752	39054	35688
December						
Competitive Price ($/MWh)	46.49	36.14	36.2	30.91	28.19	26.18
Cournot Equilibrium Price ($/MWh)	48.89	41.91	42.12	34.47	33.27	29.02
Market Quantity	45992	43559	41028	39539	34587	31715

Table 12: Partial Divestiture, elasticity = 0.1

Demand Level	Peak	150th highest	300th highest	450th highest	600th highest	744th highest
March						
Competitive Price ($/MWh)	26.69	25.95	25.95	25.25	23.97	22.96
Cournot Equilibrium Price ($/MWh)	27.45	27	27	25.42	25.18	23.87
Market Quantity	38128	35554	33545	28017	24819	22657
June						
Competitive Price ($/MWh)	30.44	26.18	25.23	24.41	23.16	20.84
Cournot Equilibrium Price ($/MWh)	64.19	27	25.42	25.18	24.2	20.83
Market Quantity	51906	42723	37805	32092	27079	22003
September						
Competitive Price ($/MWh)	124.88	33.93	32.09	26.78	24.37	22.96
Cournot Equilibrium Price ($/MWh)	427.83	159.13	121.2	28.05	25.18	23.87
Market Quantity	48810	41255	38444	36223	30337	26355
December						
Competitive Price ($/MWh)	34.01	28.73	28.82	26.98	25.76	25.16
Cournot Equilibrium Price ($/MWh)	129.62	54.93	54.93	28.13	27.04	25.42
Market Quantity	41394	38286	36155	32661	28156	24381

Table 13: Partial Divestiture, elasticity = 0.4

Demand Level	Peak	150th highest	300th highest	450th highest	600th highest	744th highest
March						
Competitive Price ($/MWh)	27.5	27.06	27.01	26.18	24.37	23.47
Cournot Equilibrium Price ($/MWh)	28.17	27.46	27.9	27	25.18	24.2
Market Quantity	42185	38942	36900	31161	26658	25199
June						
Competitive Price ($/MWh)	34.74	27.3	26.18	25.43	23.89	22.18
Cournot Equilibrium Price ($/MWh)	45.97	27.46	27	26.07	24.2	22.17
Market Quantity	54176	47010	41616	35511	30263	24775
September						
Competitive Price ($/MWh)	68.62	43.44	36.71	28.2	25.43	23.56
Cournot Equilibrium Price ($/MWh)	69.34	52.36	46.72	31.55	25.42	24.2
Market Quantity	53771	44642	41770	38991	33703	29439
December						
Competitive Price ($/MWh)	38.49	30.25	30.42	26.78	26.18	25.43
Cournot Equilibrium Price ($/MWh)	48.92	33.68	33.68	28.05	27.83	25.42
Market Quantity	44755	42109	39765	35875	30916	27094

Table 14: Full Divestiture, elasticity = 0.1

Demand Level	Peak	150th highest	300th highest	450th highest	600th highest	744th highest
March						
Competitive Price ($/MWh)	26.69	25.95	25.95	25.25	23.97	22.96
Cournot Equilibrium Price ($/MWh)	27.45	27	26.17	25.42	24.3	23.87
Market Quantity	35658	33838	31123	26020	22688	22567
June						
Competitive Price ($/MWh)	30.44	26.18	25.23	24.41	23.16	20.84
Cournot Equilibrium Price ($/MWh)	32.07	26.24	26.07	25.18	23.87	20.83
Market Quantity	49253	39648	34918	29513	26366	21695
September						
Competitive Price ($/MWh)	124.88	33.93	32.09	26.78	24.37	22.96
Cournot Equilibrium Price ($/MWh)	186.13	58.17	58.17	28.05	25.18	23.74
Market Quantity	47163	39915	36867	33004	28228	25887
December						
Competitive Price ($/MWh)	34.01	28.73	28.82	26.98	25.76	25.16
Cournot Equilibrium Price ($/MWh)	58.35	29.28	32.38	28.06	26.81	25.18
Market Quantity	39826	35513	34159	29903	26502	23543

Table 15: Full Divestiture, elasticity = 0.4

Demand Level	Peak	150th highest	300th highest	450th highest	600th highest	744th highest
March						
Competitive Price ($/MWh)	27.5	27.06	27.01	26.18	24.37	23.47
Cournot Equilibrium Price ($/MWh)	28.17	27.45	27.45	27	25.18	24.2
Market Quantity	39146	36104	33897	28959	24718	23659
June						
Competitive Price ($/MWh)	34.74	27.3	26.18	25.43	23.89	22.18
Cournot Equilibrium Price ($/MWh)	39.79	27.46	27	26.07	24.2	22.28
Market Quantity	50752	42724	38348	32612	27997	24758
September						
Competitive Price ($/MWh)	68.62	43.44	36.71	28.2	25.43	23.56
Cournot Equilibrium Price ($/MWh)	69.34	46.27	41.34	28.19	25.42	24.2
Market Quantity	48372	40625	37798	35311	30598	27958
December						
Competitive Price ($/MWh)	38.49	30.25	30.42	28.19	26.18	25.43
Cournot Equilibrium Price ($/MWh)	43.87	32.38	33.59	28.64	27.04	25.99
Market Quantity	40832	38261	35453	32248	28876	25919

Table 16 — Market outcomes for base case with elasticity = 0.1 and Linear Demand

Demand Level	Peak	150th highest	300th highest	450th highest	600th highest	744th highest
March						
Competitive Price ($/MWh)	26.66	25.88	25.88	25.25	23.97	22.96
Cournot Equilibrium Price ($/MWh)	58.35	27.45	27	27	25.18	24.2
Market Quantity	40085	38771	36471	31079	26237	23272
June						
Competitive Price ($/MWh)	29.91	26.18	25.19	24.39	23.11	20.84
Cournot Equilibrium Price ($/MWh)	126.11	27.45	26.24	25.42	24.2	20.83
Market Quantity	48372	42480	37548	31890	26902	21819
September						
Competitive Price ($/MWh)	104.76	33.93	32.08	26.69	24.34	22.96
Cournot Equilibrium Price ($/MWh)	178.12	144.94	132.26	63.08	25.42	24.2
Market Quantity	49649	40118	37157	34728	30147	26170
December						
Competitive Price ($/MWh)	33.81	28.73	28.81	26.86	25.69	25.06
Cournot Equilibrium Price ($/MWh)	135.69	104.48	100.9	54.93	28.06	25.42
Market Quantity	40050	36241	34363	31596	27980	24235

Table 17— Market outcomes for base case with elasticity = 0.4 and Linear Demand

Demand Level	**Peak**	**150th highest**	**300th highest**	**450th highest**	**600th highest**	**744th highest**
<u>March</u>						
Competitive Price ($/MWh)	27.5	26.78	26.66	25.95	24.31	23.31
Cournot Equilibrium Price ($/MWh)	45.97	27.46	27.9	27	25.18	24.3
Market Quantity	41538	41879	39309	33614	28523	25359
<u>June</u>						
Competitive Price ($/MWh)	33.89	26.94	26.08	25.25	23.56	21.45
Cournot Equilibrium Price ($/MWh)	58.17	27.46	27.45	26.24	25.18	21.95
Market Quantity	51332	45886	40509	34537	29215	23905
<u>September</u>						
Competitive Price ($/MWh)	67	42.76	35.26	28.14	28.14	23.31
Cournot Equilibrium Price ($/MWh)	73.56	58.17	58.17	49.9	47.9	24.3
Market Quantity	52294	43529	39715	35577	32650	28517
<u>December</u>						
Competitive Price ($/MWh)	37.22	29.75	29.94	27.9	26.12	25.27
Cournot Equilibrium Price ($/MWh)	58.35	54.54	53.71	44.44	28.13	25.99
Market Quantity	42947	38110	36117	32827	30164	26272

Appendix B- Data Sources

Thermal Generating Plant Data

Costs of thermal generating plants were derived using the inputs from General Electric's MAPS multi-area production cost simulation model obtained from CEC staff. Plant status and capacities were cross checked with the Energy Information Administration's 1994 Inventory of US Generating plants (DOE/EIA, 1995) for plants not owned by California utilities. Generation plants owned by California utilities were also cross checked with plant capacities in appendix A of the CEC's 1994 electricity report (ER94). "Available" plant capacities were derived using the plants rated capacity multiplied by its average forced outage rate (FOR). Forced outage rates were taken from the MAPS inputs and, for California owned plants, crossed checked with FORs provided in ER94. As explained in the text, capacities are not adjusted for maintenance requirements, because the timing of such unavailability is a strategic decision of the firm.

Thermal plant operating costs were derived using the full capacity average heat rates from MAPS, and fuel cost projections used by Deb, et. al. (1996) which were derived from ER94 and other sources. To these fuel costs we added variable operating and maintenance costs taken from the MAPS data set. There is, however, a disturbing amount of variance between data sets about the capabilities and costs of plants in some regions. Fortunately, the larger source of information available for California owned facilities is much more consistent across data sets.

Table 18: Forecast Delivered Gas Prices ($/Mcf)

Period	*Northwest*	*Nor. Cal.*	*So. Cal.*	*Rocky Mt. N.*	*Rocky Mt.- SW*
December	2.18	2.50	2.69	2.18	2.50
March, June, Sep	2.04	2.31	2.50	2.04	2.31

Table 19: Incremental Costs of PG&E and SCE (using summer gas prices)

	PG&E		**SCE**	
Incremental $/MWh	**Total Capacity**	**Cum Capacity (GW)****	**Total Capacity**	**Cum Capacity (GW)****
0-4.90	4.26*	4.26	1.128*	1.128
5.00-9.90	0.00	4.26	0	1.128
10.00-14.99	1.90	6.16	2.629	3.757
15.00-19.90	0.00	6.16	0.734	4.491
20.00 - 24.90	4.34	10.50	5.751	10.242
25.00 - 29.90	2.51	13.01	2.208	12.45
30.00 - 34.90	0.05	13.06	1.082	13.532
35.00 - 39.90	0.04	13.11	0	13.532
40.00-44.90	0.00	13.11	0	13.532
45.00-49.90	0.00	13.11	0	13.532
50.00 - 54.90	0.38	13.48	0	13.532
55.00 and up	0.04	13.52	0.132	13.664

*Includes maximum instantaneous flow capacity of pondage hydro
**thermal unit capacities derated by forced outage rates

Divestiture of Gas-fired Generation Capacity

The partial divestiture scenario involved creating 3 new Cournot firms, one that owned 1/2 of PG&E's gas resources, and two that each owned 1/2 of SCE's gas resources. The full divestiture scenario was based upon 1998 announcements of the actual sales agreements that have been reached. Table 22 shows the allocation of thermal capacity before and after these announced transfers are completed.

Table 20 — Pre and Post Divestiture California Thermal Capacity

Incumbent Firms	Pre Divestiture	'Full' Divestiture
PGE	8083 MWs	782 MWs
SCE	12314	1378
New Firms		
Duke		2306
AES/Williams		3705
Houston Ind.		3554
Destec		1445
Thermo Ecotek		249
TBD*		3093

*To be divested – purchasing firm not yet identified.

Hydro Generation Data

Hydro plant data were taken from the data set used by Southern California Gas Company in its 1995 performance-based ratemaking simulation studies (Pando, 1995). This data set was also used by Kahn, et. al (1996) in their simulation analysis of the WSCC. The minimum and maximum flow capacities of the hydro resources shown in Table 2 are taken from this data set. Monthly hydro energy production values were primarily derived from the Energy Information Agency's *Electric Power Monthly* (EIA). The values used for U.S. production are four-year averages of the production in each respective month. The production by the Canadian members of the WSCC was taken from the 2001 production forecast given in the WSCC report *Expected Loads and Resources* (WSCC, 1996).

The data provide instantaneous maximum and minimum MW outputs for hydro-systems in the WSCC as well as monthly energy (MWH) quotas for each facility or set of facilities. Hydro facilities fall into three categories - pondage, run-of-river, and pumped storage. Run-of-river capacity is derived from the minimum flow rates of each of these facilities and the respective energy used through run-of-river was deducted from each system's monthly energy quotas. In order to derive the amount of standard pondage capacity that would be available in any given hour, we allocated the remaining monthly energy across the hours of a month in a process known as "peak-shaving." Such an allocation of hydro energy assumes that the highest output will occur in the highest demand hour and respectively less capacity would be available for lower demand hours. As long as the instantaneous flow capacity of hydro facilities were not violated, the peak shaving process would leave a constant level of demand to be served by non-hydro sources over the hours to which pondage hydro generation was applied. If the maximum flow capacity was a binding constraint, the peaks would be shaved as much as possible, but still be left with a higher level of demand than other near-peak hours. Peak-shaving was performed regionally – California hydro energy was applied to aggregate California load shapes, and likewise for the Northwest and Southwest regions. Peak-shaving is an approximation to the marginal revenue equalization that an optimizing firm would actually pursue, as described in the text.

Pump-storage units were assumed to be available in the two highest demand runs and assumed to be unavailable during the four low-demand hours. There were three pumped storage units represented: 1188 MW owned by PG&E, 217 MW owned by SCE, and 1287 MW owned by LADWP. These figures are taken from ER94. Demand in the off-peak hours was adjusted upwards to account for the additional storage into these units. The energy price of the PG&E and LADWP units was set at an estimate of the low-demand energy marginal cost, $22.50/MWH, and revised upwards to $27.50/MWH to account for energy losses in the pumping process. SCE was expected to have lower off-peak marginal costs of around $15.50/MWh which was revised upwards to $20/MWh to account for pumping losses.

Transmission Capacities

The capacities of the major transmission paths into California were taken from the non-simultaneous path-ratings of the Western Systems Coordinating Council (WSCC, 1996b) and from the most recent Southern California Instantaneous Transmission agreements (SCIT, 1996). These included a non-simultaneous capability of 4880 MW from the NW region into northern California, 2900 MW from the NW into southern California, and a total of 11326 MW from Nevada, Utah, and Arizona into Southern California. There are several path constraints that appear to be relevant when considering import capacities into southern California. These are the SCIT constraint, which includes flows from northern California, and two paths in the desert southwest - the West-of-River constraint of 9406 MW, which includes flows from Nevada, Utah, and Arizona - and the East-of-River constraint, which deals only with flows from Arizona. Because of the aggregation of States that we chose to include in our Southwest region, we used the West-of-River simultaneous import constraint to represent the limit of supply from that region. Transmission capacity into southern California is further augmented by the Intermountain DC link, which has a WSCC rated capacity of 1920 MW into California.

Demand Data

Monthly loads and load shapes were provided from the MAPS data set for a base year of 1995. These load shapes were scaled according to the summer peak forecast for the year 2001 for each region. Annual peaks for the California utilities were taken from ER94. Monthly peaks for each utility was derived by multiplying the annual peak by monthly peak factors derived from the MAPS data. The 2001 demand peak for out-of-state utilities was derived by escalating the 1995 peaks provided by the MAPS data set by the regional summer peak growth forecasts of the WSCC.

Qualifying Facilities

For our base cases, we used ER94 estimate of reliable QF capacity, 8279 MW. The capacity was derated according to the peak and off-peak capacity factor estimates given in Kito (1992). It was assumed that this capacity would be available during all hours. This assumption is consistent with those used in other studies of the California market (See Kahn et. al. (1996), Joskow et. al. (1996)). It is widely acknowledged that this figure most likely overstates the actual effective capacity of QF generation. The ER94 capacity estimate does not consider the fact that the majority of QFs will be receiving considerably lower payments due to the expiration of the fixed energy price period of their contracts.

Appendix C – Hydro Sensitivity Analysis

Table 21: Effect of increased hydro production on base case prices

Demand Level	**Base case Energy Price at Cournot Equilibrium - Elasticity = .1 ($/MWh)**							
	September				December			
	Average Hydro		95-96 Hydro		Average Hydro		95-96 Hydro	
	Perfect Compet.	Cournot	Perfect Compet.	Cournot	Perfect Compet.	Cournot	Perfect Compet.	Cournot
Peak	**124.88**	**4829.24**	**91.95**	**3289.16**	**34.01**	**421.22**	**26.62**	**156.62**
150th highest	**33.93**	**932.18**	**28.20**	**290.83**	**28.73**	**150.88**	**27.91**	**54.93**
300th highest	**32.09**	**555.08**	**29.08**	**304.96**	**28.82**	**137.58**	**27.93**	**32.38**
450th highest	**26.78**	**63.08**	**26.78**	**58.35**	**25.59**	**28.13**	**26.21**	**27.90**
600th highest	**24.37**	**25.42**	**24.37**	**25.42**	**25.76**	**28.06**	**25.43**	**27.04**
720/744 highest	**22.96**	**24.2**	**22.96**	**24.2**	**25.16**	**25.42**	**24.76**	**25.18**

Table 22: Effect of increased hydro production on partial divestiture prices

Demand Level	**Divestiture Energy Price at Cournot Equilibrium - Elasticity = .1 ($/MWh)**							
	September				December			
	Average Hydro		95-96 Hydro		Average Hydro		95-96 Hydro	
	Perfect Compet.	Cournot	Perfect Compet.	Cournot	Perfect Compet.	Cournot	Perfect Compet.	Cournot
Peak	**124.88**	**427.83**	**91.95**	**337.96**	**34.01**	**129.62**	**26.62**	**58.35**
150th highest	**33.93**	**159.13**	**28.20**	**58.17**	**28.73**	**54.93**	**27.91**	**28.18**
300th highest	**32.09**	**121.20**	**29.08**	**58.35**	**28.82**	**54.93**	**27.93**	**28.01**
450th highest	**26.78**	**28.05**	**26.78**	**27.90**	**25.59**	**28.13**	**26.21**	**27.83**
600th highest	**24.37**	**25.18**	**24.37**	**25.18**	**25.76**	**27.04**	**25.43**	**25.99**
720/744 highest	**22.96**	**23.87**	**22.96**	**23.87**	**25.16**	**25.42**	**24.76**	**25.18**

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