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Looking for Trouble: Competition Policy in the U.S. Electricity Industry

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Abstract

In the aftermath of the California energy crisis, there has been a shift in the focus of electricity regulators away from the fostering of a competitive market structure and towards the application of regulations to specific market outcomes. Such a focus stands in marked contrast to the general principles governing competition policies in other industries. This shift is in part influenced by the clear failure of earlier attempts to establish a competitive market structure in California. But was this a failure of the policy, or of the tools that were used to implement it? In this chapter, I describe the tests historically used by regulators as screens for the potential abuse of market power by suppliers.

More advanced methods, such as models of oligopoly competition, can potentially provide a much better understanding of the competitive outlook for a market. However, much uncertainty surrounds the development and application of such models. I apply an oligopoly model of the California market to actual market data to test the ability of such models to recreate true market outcomes. I also explore the potential impacts of structural changes in the California market on both the supply and demand-side. The results indicate that either a reduction in supplier concentration or an application of real-time pricing to end-users would have yielded cost savings on the order of billions of dollars during the summer of 2000.

1.0 Introduction

As the U.S. electricity industry has been transformed over the last 25 years, many of the laws and regulations that had formed the foundation of the industry's organization are increasingly poor matches for the task of achieving the policy goals for which they were designed. The sets of laws and regulations that form competition policy in the electricity industry epitomize this trend. Competition policies have been stretched to accommodate the wide variety of market and regulatory contexts in which they have been applied. This is particularly true for market power screens, which are used to test if a market has a sufficiently competitive structure. Procedures that had been developed primarily to review mergers and wholesale transactions between regulated, vertically integrated utilities have been applied with little change to the context of largely deregulated markets dominated by non-utility generation companies. The spectacular failure of the California market has drawn attention to the risks of this approach.

In the aftermath of the California crisis of 2000 and 2001, there has been a quiet revolution in the thinking of electricity regulators toward competition policy. In some contexts, the structural market power screens over which there had been much debate in the late 1990's are being set aside altogether in favor of more active pricing regulations to be applied by regional Independent System Operators (ISOs) under the rubric of market power mitigation. These policies constitute a shift in focus away from fostering a competitive structure and market *process* towards the application of regulations to specific market *outcomes*. Such a focus stands in marked contrast to the general principles governing competition policies in other industries.

This policy shift can in part be attributed to the fact that the traditional structural screens so clearly failed to achieve their purpose in California. The physical attributes of electric energy make it inherently vulnerable to the exercise of market power. If setting up a reliably competitive market structure is impossible, all that is left is to regulate prices. Yet such a reaction begs the question of whether the failure should be attributed to the professed goal of establishing a competitive structure that would require little subsequent regulation, or to the specific tools that were applied to implement that concept. While California demonstrated the obsolescence of the traditional standards for a competitive market structure that were holdovers from the era of vertically integrated utilities, there were plenty of other warning signs of trouble. These warnings were largely ignored until the market was deep into crisis.

In this chapter, I describe the methods that have traditionally been applied as screens for competitiveness problems in the electricity industry, as well as some of the alternatives that appear to be much better suited to restructured electricity markets. One such alternative is the simulation of explicit market operations under various assumptions of oligopolistic competition. While there is extensive academic experience with the application of such models to electricity markets, they have had almost no impact on policymaking. Until recently, there also had been few attempts to test the veracity of such models. Evidence from Bushnell (2003) indicates that such models can provide relevant insights into the performance of electricity markets.

The richness of detail that is available from oligopoly models allows for the examination of counter-factual experiments about the impact of market structure. To demonstrate this potential, I utilize the model of Bushnell (2003) to explore the market impact of a more competitive industry structure on the California market during the summer of 2000. Such richness of detail also creates problems for policymakers. The models are much more complicated than the standardized approaches that have been applied to date. The increased sophistication of analysis creates the risk of bogging the process down in the examination of countless possible scenarios and outcomes. Increased complexity also makes it more difficult to interpret the impact of various assumptions on model results. One of the great challenges of adapting such models for policy analysis would be striking the proper balance between these considerations.

The results described here demonstrate that it is premature for policy makers to throw up their hands and abandon attempts at structural solutions to electricity market competition. This is not to say that structural solutions are a panacea, only that their potential benefits are real enough to warrant a serious discussion about the methods that might be used to achieve more competitive market structures, the potential costs of such methods, and the potential costs of the alternative forms of regulation that are evolving as substitutes for competitive market structures.

2.0 Competition Policy in the U.S. Electricity Industry

For most industries, competition policy in the United States is generally concentrated within state and Federal antitrust laws. The underlying philosophy of these laws is outlined in the Federal Sherman Act of 1890 and Clayton Act of 1914. The focus of these acts is not on the pricing or production policies of dominant firms, *per se*, but rather on actions taken to achieve or maintain dominant status. The simple unilateral exercise of market power by a single firm is generally not subject to antitrust actions. Thus the spirit of U.S. competition policy is to *prevent* situations in which firms can exercise substantial market power, but not to regulate the behavior of firms that find themselves in dominant positions anyway.

Given this philosophy, U.S. antitrust policy has largely focused on preventing the formation of uncompetitive market structures, primarily through reviews of mergers, alliances, and joint-ventures as well as prosecuting attempts at explicit collusion between firms. Periodically there have been attempts to implement structural remedies in markets that are already dominated by a single firm, but with the exception of the AT&T case, these efforts have not met with much success.

Under the Federal Power Act (FPA) of 1935, the FERC has jurisdiction over wholesale electricity transactions and their supporting transmission arrangements and has a statutory mandate to ensure that rates meet a "just and reasonable" standard.[1] In defining its regulatory obligations in terms of pricing outcomes, rather than competitive process, the FPA gives the FERC a mandate that goes well beyond those of the anti-trust authorities that oversee competition policies in other industries.[2] The FERC has wide discretion in determining a just and reasonable rate, however, and has at times chosen to define such rates in terms of the market environment from which they arose rather than in terms of pricing levels or cost-based measures.[3]

Until the late 1990's the vast majority of wholesale electricity trades were between utilities whose retail rates were regulated at the state level. Electricity policy at the FERC therefore naturally focused on the vertical relationship between generation and transmission facilities. In order to foster the development of 'independent' non-utility generation, the FERC has attempted to implement a series of rulings intended to grant independent generators access to utility owned transmission facilities. Horizontal market power concerns were much less prominent. The two areas in which horizontal market power issues were periodically addressed were in the review of mergers and the granting of "market-based" rate authority for wholesale transactions. Both of these processes involved a review of the market structure in which the subject producer would be operating. Although there was certainly large disagreement over the development and application of those structural screens, they were at their core attempts to *ex-ante* promote a more competitive market structure. I explore the evolution of those screens in more detail in the following subsections.

It is important to recognize that until 1996, the analysis of both mergers and applications for market-based rates involved evaluating relatively incremental changes to the underlying markets. Most firms were still vertically integrated and regulated at the state level. Even the merger of large utilities produced a relatively modest impact on the wholesale markets since those markets accounted only for residual transactions, and the bulk of electricity was still produced internally by local utilities. The shortcomings of the FERC's standard analytic approaches were largely concealed by the incremental nature of these changes. The restructuring of regional markets, starting with California in 1996, changed all that. Instead of evaluating the incremental impact of market-based rate authority granted to a single utility, the FERC was now tasked with determining whether market-based rates applied to an entire regional market would produce just and reasonable outcomes. The problems with the FERC's traditional market-power screens were exposed to a dramatic extent by ensuing events in California.

2.1 Merger Review Policies at FERC

Section 203 of the FPA provides that the FERC review all utility mergers or sales of facilities under its jurisdiction with a value in excess of $50,000. The act dictates that FERC must determine that the proposed merger or transaction is "consistent with the public interest," before approving it.[4] In 1996, the FERC issued a policy statement intended to clarify its interpretation of the public interest standard and lay out a standardized framework for analyzing merger proposals.[5] The procedure drew heavily from the merger guidelines of the FTC and DOJ. In the policy statement, the FERC adopted a process for screening proposed mergers for the likelihood of anti-competitive effects.[6]

Appendix A of the policy statement outlines the procedure to be used as a horizontal market power screen. This has served as the blue-print for merger reviews in the industry since its adoption in the 1996. The process involves first identifying the relevant products, then determining the geographic scope of the market for those products, and finally estimating the price impact of the proposed merger by measuring its impact on the concentration of suppliers in that geographic market. The FERC usually considered the relevant products to be non-firm energy, short-term capacity (firm energy), and long-term capacity. These are the products most frequently traded between vertically integrated utilities in markets that have not been restructured around a market for "spot" energy, such as those in California and the northeast.

Defining Geographic Markets

The task of defining the scope of the relevant market has tended to be the most important, and therefore most contested, aspect of merger cases. The 1996 FERC policy statement describes the process of identifying a "destination" market of relevant consumers and applies a "delivered price" test to determine potential suppliers. The delivered price test includes as potential suppliers all generation units from which energy could be generated and transmitted to the destination market at a cost no more than 5% greater than the price in the destination market that would result if there were no merger. The delivered price test therefore boils down to an examination of whether a specific firm could profitably raise prices by 5% in the one target market, taking into consideration potential competition from neighboring suppliers.

The delivered price test has been criticized for its implicit assumption that firms can raise prices in the destination market without affecting prices in neighboring markets. In the absence of transmission constraints, such pricing separation is usually not the case in electricity markets.[7] Another problem with the delivered price test as described in the

1996 merger policy statement is that it doesn't give any guidance about how to deal with the potential for transmission congestion. Unlike most other markets of interest to antitrust authorities, geographic markets in electricity are determined not only by the *costs* to potential competitors of transporting their product, but by their physical ability to ship it at *any* cost. In terms of its potential impact on market prices, such transmission capacity constraints present a very different problem than that usually encountered in merger analysis in other industries.

In many other, durable goods, industries the type of "competitive harm" that is of concern is the ability of merging firms to sustain a modest but still significant (*i.e.* 5%) price increase. Large price increases would likely draw imports, but still result in higher prices due to the higher transportation costs of those imports. In electricity, limits on transmission capacity, combined with the lack of economic storage, create circumstances in which there may be no additional competitive supply in the short term *at any price.* Such circumstances, in which a single supplier is *pivotal* (*i.e.* monopolizes a portion of the market demand) result in periodic extreme price increases rather than smaller increases sustained continuously over longer periods of time. Ironically, the focus on the ability to sustain small increases sometimes overlooks the more serious problem. In some cases an electricity supplier may not find it profitable to raise prices by 5%, but would find it profitable to raise prices by 500%.

The physical properties of electricity transmission carry implications for both the evaluation of firm incentives, which is discussed below, as well as for the definition of a geographic market. Clearly if transmission capacity limits power flow into a region, those limits also define the scope of the market. However, capacity limits only bind some of the time, and it is difficult to predict just how often they will be relevant. The physical properties of electricity transmission greatly complicate this task. Power is injected and withdrawn from an integrated network, rather than "shipped" from one point to another, as in a railroad network. The actual path taken by power flows is determined by the physical characteristics of the network rather than by commercial transportation arrangements.[8]

Recognition of this problem, among others, within FERC led to the convening of a technical conference in 1998 on the use of computer models in merger analysis (FERC

Do. No. PL98-6-000). The FERC solicited comments on its proposals to utilize industry computer models to predict the impact of mergers on transmission congestion and prices. Specifically, a staff white paper outlined a proposal to utilize industry models, know as production cost models and power flow models, that optimize both the supply of power and the transportation of it, respectively. These models would help provide a more sophisticated picture of the cost of delivering power to the target market and, according to the proposal, allow for a more accurate application of the delivered price test.

While it is difficult to argue with the notion of using a computer to aid in merger analysis, the specific FERC proposals drew considerable skepticism. Many parties objected to the continued application of the delivered price test to a single "destination" market.[9] As described above, this amounts to an implicit assumption about the ability of the merging firms to price discriminate between sub-markets. A firm that can price discriminate would potentially have more incentive to raise prices in a destination market, and therefore raise more of a concern over a potential merger than if it could not price discriminate. Yet the adoption of models that simulate a market equilibrium over a much larger region implicitly assumes the opposite, that differential prices could not be sustained absent physical transmission limitations. It was argued that the delivered price test should be discarded in favor of a more global evaluation of regional price impacts.

Another set of comments were concerned with the proposal's potential to understate market power because it did not explicitly model the incentives of firms to create congestion, thereby creating smaller geographic markets.[10] The models proposed by the FERC utilized an objective function of minimizing costs. Operating under such an objective function, the model would ascertain the least-cost set of generation available to satisfy demand and model the resulting power flows and transmission congestion accordingly. Thus the models would produce a prediction of the level of transmission congestion that would result from a perfectly competitive market, and then apply market power screens to the geographic markets produced by such models. However, to the extent that firms explicitly recognize that they can profit from creating additional congestion, such models will understate the level of congestion, and produce unrealistically large geographic markets.[11]

The key problem with the 1998 proposals was that they tried to apply improved tools to a flawed process. The delivered price test has never reflected the reality of wholesale electricity markets. The focus on incremental price impacts sometimes missed the potential for far more significant, if less persistent, price impacts. The adoption of models utilizing an objective of least-cost production could understate the amount of congestion that could realistically be experienced when suppliers acted strategically. Finally, and most seriously, the proposals did not address a key shortcoming of the Appendix A process, its reliance on a measure of supplier concentration, the Hirschman Herfindahl Index (HHI) for the assessment of potential price impacts. This problem is discussed in more detail in the following section.

The Evaluation of Price Impacts

As described above, the three steps to a merger analysis under FERC's merger policy statement are the definition of the relevant products, the determination of the geographic scope of the market, and the measurement of potential price impacts on those markets. Although the greatest concern about mergers are their impacts on prices, in practice the potential market impacts are screened through the application of concentration measures. In particular, Appendix A of the merger policy statement lays out explicit guidelines for the use of the Herfindahl-Hirschmann Index (HHI).[12] Unfortunately, concentration measures are very imperfect measures of potential market power, and the physical characteristics of electricity markets greatly magnify their shortcomings. The extent to which FERC based important policy decisions upon concentration measures was one of the greatest problems with U.S. electricity competition policy in the 1990s.

The reliance upon HHIs as a screen for potential horizontal market power problems is derived from FERC's interpretation of the FTC/DOJ merger guidelines, which also describe the application of concentration measures. Even so, the shortcomings of concentration measures are widely recognized at the FTC and DOJ and most serious reviews of mergers go well beyond them. FERC merger policy, and its decisions on market-based rate authority for individual firms, by contrast, place much more importance on the HHI than do the agencies from which it was adopted.

FERC's Appendix A describes several thresholds that indicate a potential cause for concern and would trigger a call for more detailed analysis. A market with a post-merger HHI below 1000 is considered unconcentrated, and a merger is considered to unlikely to cause competitive harm regardless off the increase in HHI. A market with a post-merger HHI between 1000 and 1800 is considered to be moderately concentrated, and a merger that causes the HHI to increase by more than 100 would raise potential concern. A market with a post-merger HHI over 1800 is considered to be highly concentrated, and an increase of more than 50 would potentially raise significant concerns.

Various measures of firm 'size' are proposed. The two most commonly applied measures are that of *economic generating capacity*, which measures the amount of generation capacity a firm could supply to the destination market at a cost no greater than 105% of the estimated pre-merger price in that market, and *available economic generation capacity*, which subtracts a firm's internal demand obligations from its available economic capacity. This latter measure is appropriate for vertically integrated utilities that are obligated to serve their native demand at some cost-based rate. For example, a large firm with 10,000 MW of generation capacity that also has an obligation to supply power to 9000 MW of demand is really only free to pursue wholesale sales on its 'spare' 1000 MW of generation capacity.

The application of Appendix A, and related analyses are characterized as 'screens' for potential competitive harm. If the screening thresholds are exceeded, then further analysis is called for. Such a practice assumes that the screen is a conservative measure that is likely to overstate the potential for market power. Thus closer examination is warranted when the screen is triggered to reduce the likelihood of a 'false-positive' determination of competitive harm. However, these guidelines, however, are far more likely to *understate*, rather than overstate the potential severity of market, at least in their application to restructured electricity markets.

Problems with Concentration Measures

The logic behind the application of concentration measures is derived from the obvious relationship between a firm's size and its ability to influence market prices. The essential question that a competition analysis is trying to answer is, what would happen to market prices if the subject firm attempted to raise offer prices or withhold its output? For a firm that is 'large' relative to the market, any reduction in output would likely not be completely replaced by other firms. By contrast, the reduction in output by a 'small' firm should have little impact on prices since the production could more easily be replaced by other firms. Such logic is much more persuasive in a circumstance where a product is inexpensive to store, production can be expanded relatively easily, and customers are responsive to changes in market prices.

Unfortunately, such conditions do not exist in electricity markets. Electricity, with the exception of some hydro facilities, cannot be economically stored. The lack of storage means that short-term limits on both generation and transmission capacity can create very 'tight' markets, with little extra unused production capacity. Finally, while wholesale spot prices for electricity can vary significantly from hour to hour, the rates of the vast majority of end-use customers are at best adjusted annually. Thus even if end-users were inclined to reduce their consumption in response to a price-increase, they have no incentive to do so. The price increase likely won't show up in their bill for several months.

The problems with concentration measures under such conditions are best illustrated with an example of a 'tight' electricity market. Consider a market with 10 equal sized producers, each with generation capacity of 1000 MW. This would yield an unconcentrated HHI level of 1000. If demand in this market were 5000 MW, then any production withdrawn by a single producer would likely be nearly completely replaced from the large amount of remaining idled production. However, if demand on a hot summer day rose above 9000 MW, then at least some production is required from *every* supplier. In other words, each supplier would be able to monopolize at least a portion of the market demand. As demand rises, each firm faces less risk that a reduction in output would be replaced by one of the other firms. In the absence of price-responsive demand, there is no market mechanism that can restrain the ability of firms to raise prices.

Importantly, Appendix A declares that its guidelines are truly simply guidelines and not strict rules that would be rigidly applied. In practice, FERC has indeed shown some flexibility in its application of its guidelines in merger proceedings. However, as described below, similar criterion have also been applied to the granting of market-based rate authority and its application there has been more problematic. Because of the large number of requests FERC receives for market-based rate authority, it has applied these guidelines much more literally as a 'screen' of potential problems.

Unfortunately, while mergers have usually received more advanced scrutiny than applications for market-based rates, certain market-based rate proceedings have carried much greater risk of a 'false-negative' finding of a low potential for market power. This is because we have yet to see a merger that has significant impact on the market structure of a restructured U.S. market. Even if the FERC's merger policies bias against the finding of market power, and as a whole it is not obvious that they do given the context in which they have been applied, the consequences of such a bias have been minimized by the fact that the merger parties have for the most part continued to be regulated by state or other authorities. As described below, this is not the case with applications for market-based rates.

2.2 Market Based Rate Authority

Unlike merger proceedings, proceedings over market-based rate authority have produced some of the key regulatory decisions that paved the way for the opening of restructured markets in California and the northeastern states. Many of the suppliers in these markets had no state-regulated retail load obligations. The granting of market-based rates therefore constituted the removal of the last significant regulatory constraint on the pricing practices of many of the firms in these markets. The potential consequences of a false-negative finding of low potential market power were therefore enormous. The FERC is aware of the problems with its market power screens, and has been trying to develop alternatives over the last several years. Interestingly, it appears that one of the leading alternatives is to abandon structural screens altogether in restructured markets in favor of a regime of more direct price regulation.

The FERC allows sales at market-based rates if “the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry.”[13] For the bulk of its history, FERC relied upon a market power screen known as the “hub-and-spoke” test, for determining whether a firm was eligible to sell a given product at market-based rates. Although based upon the same principles as the Appendix A merger analysis, the hub and spoke test applied standards that were much more favorable to the applicant.

The destination market, or hub, is defined as the applicants home service territory, and the geographic market is defined to include all adjacent connected utilities that have filed open-access transmission tariffs with the FERC. The test then measures the ratio of the applicant’s installed generation capacity divided by the capacity of all installed generation in the geographic market. It also measures the ratio of “uncommitted” capacity, where the load obligations of both the applicant and other firms are subtracted from installed capacity. If neither of these ratios exceeded 20% (*i.e.*, if the applicant had less than a 20% share of both measures), the applicant was considered to have no market power in generation.

As described in a FERC staff white-paper on the subject,[14] the hub and spoke test was developed during a period “when trading was predominantly between vertically integrated IOUs and market-based rates functioned as an incentive for vertically integrated utilities to file open access transmission tariffs into what were then largely closed and concentrated markets.” When it was developed, the test reflected the FERC’s focus on vertical concerns over horizontal ones. The horizontal screens were intentionally generous in order to provide incentives for firms to provide transmission access to outside generation sources. As observed in the white paper, “hub and spoke worked reasonably well for almost a decade when the markets were essentially vertical monopolies trading on the margin and retail loads were only partially exposed to the market.”

By the second half of the 1990’s, however, almost all utilities had filed open access transmission tariffs with the FERC. The relevant geographic market for most applicants therefore encompassed the applicants own control area and all adjacent ones, regardless of the transmission capacities connecting those regions. The result was a screen that almost no firms failed to pass. In markets dominated by vertically integrated, state-regulated utilities, this had little impact.

The restructured markets, however, were a different story. Because of the shortcomings of concentration measures described above, the test determined that firms had no market power in contexts, such as California, in which they clearly did. In the words of FERC commissioner Massey, "the hub and spoke is much too primitive for these times. Clearly, the Commission must develop a more sophisticated approach to market analysis, and I would recommend that we proceed generically to do so."[15]

Beyond the hub and spoke

After declaring in December 2000 that the California Market was "seriously flawed," producing the "potential for unjust and unreasonable rates"[16] despite the fact that the suppliers in the market had easily passed the hub and spoke screen, the Commission began a search for alternative approaches to deal with market-based rate authority. In November 2001, it first applied a new screen based not upon the concentration of supply, but on the relationship of capacity ownership to overall demand in a market.[17] The new measure, called the *Supply Margin Assessment* (SMA), aims to determine if a seller is a "pivotal" supplier of a given product in a given market. The screen is applied to the applicants home control area. An applicant passes the screen if it controls an amount of generation "which is less than the supply margin (generation in excess of load) in that control area." The measured amount of generation available to supply load in a control area includes the amount of generation available to be imported into that control area, limited by the Total Transfer Capability (TTC) of the transmission system (i.e., the lesser of uncommitted capacity or TTC)." [18]

Contrasted with the hub and spoke approach, the logic behind the SMA comes much closer to capturing the dynamics of supply competition in electricity markets. It takes explicit account of transmission capacity limits. It also considers the relationship of system capacity to peak demand, which is so critical given the lack of economic storage and price-responsive demand. Despite its relative merits, the FERCs application of the SMA has been widely criticized.[19]

The SMA as proposed has only been applied to markets that have not been restructured (*i.e.* markets without FERC approved Independent System Operators (ISOs)). A firm operating in an ISO market is presumed to have its market power mitigated by its respective ISO's market power mitigation rules. Other regions tend to be dominated by large vertically integrated utilities, which are exactly the kind of firms most likely to fail the SMA test. Since such firms are still regulated at the state level, however, it is not clear what incentive such firms have to take advantage of their pivotal position. A large supplier with a concurrently large load obligation clearly has less interest in raising prices than one with no demand-side commitments. That said, firms that are allowed to 'keep' some of their trading proceeds for their shareholders do have an incentive to sell their excess capacity at high prices.

For firms operating in restructured markets, the incentive question is still somewhat murky. State regulated, vertically integrated utilities are major participants in many of these markets. Many other participants are pure generation companies, or are selling power through generation affiliates that are unregulated at the state level. For these latter firms, the incentive to raise prices when the opportunity presents itself is more clear-cut. It has been argued that the application of the SMA screen is exactly backwards.[20] Since firms in restructured markets are much more likely to behave as traditional profit-maximizing sellers, the SMA screen is much more appropriate for those markets, while it is largely irrelevant for markets dominated by players regulated at the state level.

An underlying motivation of this policy, however, is to further encourage the entry of firms into ISO supervised markets. Just as FERC once used market-based rate authority to encourage firms to file open-access tariffs, it can now use the same carrot to encourage firms to join ISOs or similar organizations. In those markets, the November order proposed to abandon structural screens altogether. Instead, it proposed to rely upon ISO market power mitigation rules to regulate the pricing behavior of firms and produce just and reasonable prices. This aspect of the order marked the culmination of a significant and under-appreciated shift at FERC away from policies more consistent with anti-trust principles and towards a more activist regulation of market outcomes.

From Regulating Structure to Regulating Behavior

Until the heights of the California crisis in November 2000, explicit competition policies at FERC had focused on creating a competitive environment in which market mechanisms could be relied upon to produce just and reasonable prices. Under this doctrine, once a competitive environment had been created, the regulation of specific prices would no longer be necessary or desirable. This focus on the process used to create prices, rather than the specific market outcomes was broadly similar to the philosophies applied by the Federal antitrust authorities.

With the creation of the eastern ISO's, FERC also approved the implementation of market-power mitigation protocols that endowed the ISO's with limited powers to regulate the offer prices of firms. By focusing on the bidding behavior of specific firms and the impact of that behavior on prices, these measures constituted a departure from regulation based on structure. Such measures were interpreted as limited, perhaps temporary tools, meant to deal with specific, infrequent conditions in which some part of the market would not be sufficiently competitive.[21] The forces of competition were expected to constrain prices in the vast majority of hours, and these regulations were intended as backup measures. Importantly, the California ISO did not possess a similar scope of regulatory powers. The only significant constraint on offer prices in the California market was a market-wide price cap.

In December 2000, the FERC had to address the California situation in the face of calls from many parties to revoke the market-based rate authority of sellers in that market.[22] The December 15th order from FERC on the California market declared that the market was "dysfunctional" and as a consequence was producing rates that were not just and reasonable.[23] The order did not identify specific parties as being at fault and did not move to revoke the market-based rate authority of any specific seller. The order did modify the price-cap in the market, however, and in doing so introduced elements of cost-based regulation. The ‘soft-cap’ introduced in that order was set at $150/MWh starting in January 2001. Under the order, supply offers could be made at levels above $150, but would be potentially have to be cost-justified to the FERC. By instituting a potential review of individual bids, the order signaled that FERC was considering an approach in California that would involve at least partial regulation of specific offer prices. As it turned out, however, the scrutiny of offers made above the $150 took the form of a more flexible (and higher) market-wide price cap. [24]

Another order on April 26, 2001 (see FERC, April 2001) expanded the scope of regulation of pricing behavior by firms in the western U.S. and also explicitly linked those regulations to conditions on market-based rate authority. In this order, FERC identified certain anticompetitive bidding practices. The order stated that "the Commission is conditioning public utilities sellers’ market-based rates to ensure that they do not engage in certain anticompetitive bidding behavior. Suppliers violating these conditions would have their rates subject to refund as well as the imposition of other conditions on their market-based rate authority." The anticompetitive bidding practices described in the order included "bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit," an example of which is "the so-called `hockey-stick’ bid where the last megawatts from a unit are bid at an excessively high price." The order also prohibited bids "that vary over time in a manner that appears unrelated to change in the unit’s performance or to changes in the supply environment." Despite the apparently increased regulatory scrutiny, no firms to date have had their market-based rate authority revoked on these grounds.

The connection between market-based rate authority and specific pricing practices was further strengthened in November 2001. In a companion order to the order first applying the SMA screen to market-based rate applicants,[25] the FERC proposed altering *all* market-based rate tariffs to include the following provision: "As a condition of obtaining and retaining market-based rate authority, the seller is prohibited from engaging in anticompetitive behavior or the exercise of market power. The seller’s market-based rate authority is subject to refunds or other remedies as may be appropriate to address any anti-competitive behavior or exercise of market power." In the order, FERC defined anti-competitive behavior to include *physical withholding*, described as a failure “to offer output to the market during periods when the market price exceeds the supplier’s full incremental costs,” and *economic withholding*, described as a supply offer “at a price that is above both its full incremental costs and the market price.”

Reactions to this proposal were strong and, to some extent, predictable. Sellers loudly protested the ambiguity of the behavioral standard and expressed dismay over the prospect of a potentially open-ended exposure to potential refunds.[26] Many public authorities countered that the proposed language was sufficiently specific, and that limitations on the time-frame for refunds would place undue pressure on FERC and other potential investigators of market abuse.[27] Within the comments, however, were many signs that the FERC had over-reached. The Federal Trade Commission (FTC, 2002) urged FERC to revive its focus on structural conditions over behavioral remedies. It also cautioned that the ambiguous standards described in the order could prove unworkable to enforce. Alfred Kahn (Kahn, 2002) described the commission’s proposal as a “substantial increase in regulation,” of a “thoroughly novel kind, far more pervasive and intrusive than the institution we purport to be disassembling.” He warned that the rules could “invite continuous scrutiny and second-guessing of what must inevitably be day-by-day, routine management decisions.” The FERC has not yet issued a final ruling in this proceeding, but other proposals originating from the Commission during this period indicate that, while the FERC may be retreating from a broad-based application of a behavioral standard, it is still intending to rely upon the regulation of pricing practices as a primary defense against market power.

Standard Market Design

Most recently, policy efforts at the FERC have been directed at the implementation of a standard market design (SMD) for wholesale electricity markets (see FERC, July 2002). It is implied that sellers participating in markets conforming to the SMD will be granted market-based rate authority with no additional structural screens (see Breathitt, 2002). The Commission recognizes structural impediments to competition, in particular the "lack of price-responsive demand and generation concentration in transmission constrained" regions, but does not propose making corrections to these problems a condition for market-based rate authority. Instead, under SMD the Commission would rely upon market power mitigation measures that would limit the market-power of sellers by restraining their behavior.

The first element of the mitigation measures would be a "safety-net" market-wide price cap that would be set at relatively high levels, such as $1000/MWh. Another element would apply unit-specific regulation to generation deemed to possess local monopoly power due to transmission constraints. A third element would encourage, or perhaps require, long-term contracting by imposing a requirement that load-serving retail entities acquire some level of reliable generation supply commitments. A fourth element that is not described in the SMD NOPR as mandatory but is strongly encouraged would be the application of some form of *automated mitigation procedures* (AMP). These measures apply continual screens of individual offer prices and alter the bids if an offer price exceeds some bound around a "reference" price level. Reference prices are usually set as some rolling average of accepted offer prices from previous hours.

The shift in policy focus from regulating structure to regulating behavior is unquestionably a significant event in the history of the industry. The relative merits of this transformation will depend upon the ultimate impacts of the newly proposed regulations, both in terms of their ability to restrict the market power of suppliers and in terms of their indirect impacts on firm's behavior and investment choices. This topic is not the focus of this paper, but I provide a brief discussion of the issues below. A second aspect to an evaluation of these new policies is a consideration of how well effective structural measures could be if they were applied with increased vigor. This is a topic explored in the following section.

Although the FERC implies that these measures may obviate the need for both structural review of firms and for imposing refund liability on suppliers, it is not at all certain that these measures would prove an adequate bulwark against market power in a market with an uncompetitive structure. The aggregate impact of these mitigation measures, and particularly of AMP measures, is not well understood at this time. The risks are two-fold. First, they may prove to be too lax to significantly hamper market-power. Both the contracting obligations and AMP are likely to lead to less volatile prices, but may not lead to lower *average* prices.

Second, by adding a layer of regulation that monitors the daily transactions of firms, these measures could significantly distort the incentives of generation and distribution firms and thereby lead to inefficient investment, operations, and transaction decisions. For example, a firm that expects the offer prices from one of its units to be restricted to be within some plausible range of the marginal operating costs of that unit may avoid efficiency-improving investments in that unit. If some of that firm's units have higher marginal costs, it allows for that firm to set higher market prices while not running afoul of the mitigation measures. Although the mitigation measures contained in the SMD proposal are not the broadly phrased restrictions on the exercise of market power that had been earlier proposed for addition to market-based tariffs, they still constitute a potentially more intrusive form of regulation than traditional cost-of-service regulation.

3.0 Market Structure and Competition

The previous sections have outlined a gradual but significant shift in FERC competition policy away from a focus on market structure and toward a focus on the regulation of pricing behavior. The Commission's traditional structural screen for market-based rates was widely viewed to be inadequate in the context of restructured electricity markets, and contributed to the crisis conditions of 2000 in California. However, its attempts to refine its structural screens have not been well received either, and the Commission's response has been to distance itself from the application of *any* structural screens in restructured (*i.e.* ISO supervised or SMD conforming) markets.

Given this trend, it is worthwhile to consider the alternative, a renewed and more aggressive focus on market structure in which firms in restructured markets would receive particular scrutiny, rather than blanket exemptions, when they apply for market-based rate authority. In assessing such an alternative path, one needs to confront two import questions: What kinds of structural screens should be applied and how much of a difference could structural changes make? Models of oligopolistic competition have great potential to contribute to the analysis of the impacts of market structure on pricing outcomes in electricity markets. In this section I provide a brief overview of their application to electricity markets and utilize a specific implementation of the modeling concept to address the question of the impact of market structure on the California market during the summer of 2000.

3.1 Oligopoly Models of Electricity Markets

One of the first instances of the usage of a market simulation model in an electricity merger proceeding was the 1995 proposed merger of Wisconsin Electric Power and Northern States Power (to be called Primergy).[28] The applicants in that case introduced a production cost model that represented the generation units in the region, and modified it to examine the impact of energy price increases by the merged firm on various potential destination markets.[29] The Primergy model was an analysis of the potential profitability of incremental unilateral price increases by a single firm in a specific destination market. This was not necessarily inappropriate for the regulatory context in which the proposed merger was taking place. Such a model, however, is not capable of assessing the overall outlook for market power in a regional market featuring several unregulated producers. A model of *oligopoly* competition is required in order to provide this broader view. A few oligopoly models have appeared in regulatory proceedings. The Supply Function Equilibrium model developed by Rudkeivich, et al. (1998) has been used in studies of the Wisconsin market, as well as the Western Resources Inc. and Kansas City Power & Light merger proceeding (see Rosen (1999)). The Cournot model of Borenstein and Bushnell has been used to study the impact of restructuring in California and New Jersey, as well as a restructuring proposal in Wisconsin.[30] To date, however, there has not been a proposed merger or acquisition that would have a significant impact on the market structure in a restructured market environment.[31] Models of oligopoly competition have therefore been more appropriate for proceedings examining the granting of market-based rate authority to firms in restructured markets. Oligopoly models have not had any significant impact in such proceedings to date.

Cournot Models of Electricity Competition

The implementation of an oligopoly model involves making several important choices and assumptions, each of which can significantly impact the results. The interpretation of such models therefore requires at least an intuitive understanding of the implications of these modeling choices. Unfortunately, the more sophisticated models are often more difficult to extract such intuition from. This balance of complexity and interpretation is one of the critical trade-offs in applying oligopoly models to policy decisions.

One of the most fundamental choices to make in modeling electricity market competition is about the way in which firms will compete with each other. Describing the form of competition involves defining the *strategy space* (*i.e.*, the decision variables) from which firms can choose as well as an *equilibrium concept* that defines how firms determine which choices or strategies are the best ones for them. [32] The most basic strategy choices involve choosing either a single offer price for all ones output or a single output quantity to be sold at the market price. The former choice, price, is associated with Bertrand models of competition and the second, quantity, is associated with Cournot models of competition.[33]

Cournot models have been widely adapted to electricity markets in the academic literature. They involve a set of firms deciding upon an output level for a given market period, based upon their knowledge of the output levels of all the other firms and assuming that the output levels of those other firms will not change. The Cournot-Nash equilibrium is the set of output levels where each firm is satisfied that its output level maximizes its profits, given the output levels of the other firms. For the most part, the application of Cournot models in electricity, as with other models, has been limited to theoretical or very stylized representations of markets. Schmalensee and Golob (1983) developed a large regional model of Cournot competition based upon actual unit-level cost data. Since restructuring in the U.S. was at that time on the distant horizon, the exercise was largely hypothetical. Borenstein and Bushnell (1998) modeled the proposed California market in great detail, utilizing plant level data encompassing the western U.S. and Canada. The accuracy of that model in the California context is discussed in more detail in following section. Cournot models have also been employed to simulate electricity markets in New Jersey (Borenstein, et al., 1998a), Scandanavia (Anderson and Bergman, 1995) and Columbia (Garcia and Arbelaez, 2002).

Oligopoly Models and Delineation of Geographic Markets

It is widely recognized that transmission congestion contributes to market power problems by reducing the geographic scope of markets. However, it is also true that market power problems contribute to transmission congestion when strategic firms detect an advantage to withholding output, inducing congestion, and further reducing the scope of competition. Historically, when transmission congestion levels were considered at all in FERC proceedings, they were treated as exogenous states of nature. An important potential advantage of oligopoly models over concentration measures is their potential ability to predict the congestion that is caused by market power.

Modeling the impact of market power on congestion levels is a very difficult problem. Models differ on whether and how they allow for strategic firms to anticipate the impact of their decisions on congestion levels.[34] To date, I am not aware of studies that assess how well individual models have predicted specific congestion levels. While this is an important topic for future research, it is beyond the scope of the analysis described below.

3.2 Evaluation of the Cournot Simulation Model

Despite their broad application to electricity markets in the academic literature, oligopoly models have met with substantial skepticism in the policy arena. For example, Frame and Joskow observed in 1998 that they were "not aware of any significant empirical support for the Cournot model providing accurate predictions of prices in any market, let alone an electricity market." In the FERC proceedings on the use of computer models for merger review, many parties commented on the importance of benchmarking and testing of these models. However, the task of assessing the accuracy and potential usefulness of oligopoly models is complicated by the need to separate out the impacts of input assumptions from those of the modeling framework.

For example, the California market was modeled within the context of the wider Western U.S. market by Borenstein and Bushnell (1999). In that paper, we estimated possible market outcomes for 2001 using 1996 vintage forecasts of such key factors as demand level, fuel prices, and hydro conditions. At the time that paper was written, even the eventual market structure in California was uncertain as the process of plant divestitures had just begun.

To control for the impact of input assumptions, Bushnell (2003) uses the actual California market data from Borenstein, Bushnell & Wolak (BBW 2002) to simulate the Cournot outcomes for that market. In adapting the model of Borenstein and Bushnell to the available market data, several important modifications were made. In general, I attempted to adhere as closely as possible to the assumptions made in BBW. The details of these modeling assumptions are described in the Appendix.

California Market Structure

Although much attention has been drawn to what FERC has described as a dysfunctional California market structure and design, generation ownership in California is actually somewhat less concentrated than in New England, PJM, New York, or Texas. Tables 1 & 2 summarize the ownership of generation in California in the summers of 1998 and 2000.

One crucial difference between California and the other restructured markets was the amount of generation owned by firms with no native load obligations. Much of the capacity in the other markets either remains owned by vertically integrated utilities or is committed to distribution companies through contracts that were imposed at the time of divestiture.[35] By the summer of 2000, almost all of the thermal generation plant in California had been divested to exempt wholesale generators (EWGs). No contractual obligations were included with those divestiture sales.

Tables 1 and 2 are therefore somewhat misleading. The two largest categories, PG&E and "QF & other" represent supply either owned or contracted to regulated utilities. The owners of this capacity are not likely to have had an incentive to exercise market power to raise prices. This is the capacity represented in Borenstein and Bushnell as "price-taking" producers, who were expected to operate as long as the market price were greater than their operating costs. The capacity share of the largest EWG, AES, is in fact less than 10% of the capacity in the ISO. By the summer of 1999, the five largest EWG's jointly controlled roughly 17GW of the 44.6 GW of capacity in the California market. Demand levels were such that at least some, and at times the bulk of that 17 GW of capacity were needed to serve load. It was under those conditions that the 5 EWGs were able to exercise market power.

We can therefore think of modeling the strategic aspects of this market as a model of competing to serve this residual demand. By assuming that the 5 large EWGs follow Cournot strategies, I can calculate the expected Nash-Cournot price for each hour using the appropriate supply costs, demand levels, and import conditions. Imports into the ISO provide the price-responsiveness of this residual demand. If prices are higher, imports increase and the residual demand declines. Figure 1, which is taken from BBW, illustrates the distribution of the demand that needed to be served by the 17 GW of capacity owned by the 5 Cournot firms over the summers of 1998, 1999, and 2000. Largely because of the reduction in import levels, the residual demand for this capacity was substantially higher in 2000 than in 1999.

Cournot Equilibrium Algorithm

Using the market data from BBW, a Cournot equilibrium is calculated for each hour of the summer of 2000. For each hour, I calculate the Cournot equilibrium iteratively. Using a grid-search method, the algorithm determines the profit-maximizing output for each Cournot 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.

At each iteration, each Cournot player faces a demand function equivalent to the market demand minus the inelastic supply from 'fringe' producers from sources such as hydroelectric, nuclear, and other 'must-take' production,[36] less the production quantities of all other Cournot players. In addition, market elasticity is provided by the presence of price-responsive imports. Therefore, although the market demand is initially assumed to be inelastic, imports provide an elasticity to the residual demand faced by the Cournot firms. More formally, every Cournot player i at time t, faces demand

$$D_{it}(P) = D_t - Q_{mt} - Q_{hydro} - Q_{imp}(P) - \Sigma_{k \neq i} S_{kt} \qquad \textbf{(1)}$$

where D_t is the market demand in hour t, Q^{mt},Q^{hydro}, and Q^{imp}, are, respectively, the production from hydro, must-take, and importing firms, and S_k is the production of Cournot firm k. More detail on the derivation of the import supply function is given in the appendix. The Cournot equilibrium is defined as the set of supply quantities, S_i, that maximize the profit of each Cournot producer given its demand function as expressed in equation (1).

Simulation Results

The results of these Cournot simulations for the summer of 2000 are summarized in Table 3. As indicated in the 'observations' column, not all hours were simulated as the method for representing the price-responsiveness of imports produced implausibly extreme demand elasticities for some hours in each month. The results from those hours are not included in these results.

For the majority of hours where the calculation of import response produced reasonable estimates, the Cournot simulation does a pretty good job of recreating actual market outcomes. The estimates produced by the Cournot simulations, by way of contrast, are much closer to market outcomes than the counter-factual perfectly competitive price reported in the last column of table 3. Figures 2-5 illustrate a kernel regression of these same prices with respect to the residual load level for each summer month. Again, the Cournot simulation results do a reasonably good job of recreating the market outcomes. For the most part, the major deviations between the kernel fits of the PX and Cournot prices appear where there were a few hours in which the Cournot solution reached the price cap at relatively low levels. This effect is largely driven by the slope of the import function. The Cournot spikes appearing when the estimated slope of imports was greater than -5 MW/$.

Impact of further divestiture

Given that the California market outcomes in 2000 resemble those produced by Cournot competition, we can employ the Cournot model to examine the potential impact of changes in the market structure. In the course of California's restructuring, some opportunities for a more competitive market structure were lost. For example, while the portfolio sales made during the spring of 1998 reduced the concentration substantially, some of the resulting portfolios were still quite substantial. Another lost opportunity was the divestiture of SDG&E's units. Ironically, concerns raised by antitrust authorities over the merger between Pacific Enterprises, owner of Southern California Gas Co., and SDG&E initiated the sale of the SDG&E plants. The bulk of the capacity was sold to Dynegy, an existing player. The south bay units were sold to the Port of San Diego, but leased to Duke energy, effectively increasing Duke's position in the market. Thus concerns about the *vertical* merger between a gas company and SDG&E led to an increase in the *horizontal* concentration in the market.

I examine the question of the impact of market structure by modeling an alternative structure that, while less concentrated, is not altogether implausible given the way the divestiture process played out in California. I model the ownership pattern summarized in Table 4. This assumes that the SDG&E units bought by Dynegy were instead sold to an unregulated new entrant and that the south bay units were operated by the Port of San Diego independently as a strategic asset. I also reduce the AES and Reliant portfolios distributing the large Alamitos and Ormond Beach units each to new entrants. Last, I separate the Moss Landing units from the remaining Duke portfolio. Table 4 also calculates the HHI for just this portion of California's capacity. Measured this way, the actual structure is 'concentrated' while the new structure falls just above the 'unconcentrated' range.

I utilize this new ownership structure to again simulate the summer months of 2000 using the Cournot model. Table 5 lists the monthly average Cournot prices resulting from the current market structure and the hypothetical less concentrated one, along with the competitive price, for the summer of 2000. Although prices still remained considerably above competitive levels, the further divestitures lowered Cournot equilibrium prices by an average of about $31/MWh in these 4 months.

To gain further insight into the hypothetical benefits of less supply concentration, I calculated the aggregate costs of market power during this period, as well as the differential impact of the further divestiture. I employ the same calculation as in BBW. This calculation takes the difference between overall ISO demand and production from must-take resources that earned regulated, rather than market prices. This difference represents the volume being purchased through the various short-term markets that operated in California during this time period. This volume is then multiplied by the market price. These results are summarized in Table 6. The differential savings from the further divestiture total over $1.8 Billion over this 4-month period. This can be compared to the estimated $4.45 Billion cost of market power for this period calculated from the Cournot equilibrium and the $4 Billion cost of market power calculated from actual prices in BBW. Thus, to the extent the Cournot simulations are reliable estimators of market impacts, the hypothetical divestiture reduces the cost of market power by about 40%.

The Impact of Contracts or Utility Ownership of Divested Units

The 2nd column of Table 5 reports the impact of further divestiture, assuming that the new owners acted as profit-maximizing Cournot firms. An alternative scenario to consider involves changing the incentives of the owners of this new set of divested units. I also therefore examine the resulting market impact of having this second set of generation units acting as price-taking firms. That is to say, these units are assumed to operate as long as the market price exceeds the marginal costs of operation. Such a change in the objectives of these units' owners could have arisen from two alternative sets of actions: the retention of this generation by the regulated utilities (who found themselves to be net buyers in the market), or the commitment these units to a long-term, dispatchable, contract. It is a rough approximation to describe the operation of either utility owned or contracted units as price-taking, but this approximation better fits the incentives of such units' owners than does an assumption of profit-maximizing Cournot behavior.[37]

As the 3rd column of Table 5 indicates, market power is greatly reduced under an assumption that the newly divested units are operated as price-takers, much more than when they were divested to Cournot firms.[38] Although the savings implied by such a result are seductive, one must consider the full implications of the assumptions that underly it. Neither scenario, contracting or utility ownership, really represents an equilibrium situation, and both carry potentially substantial costs *outside* of the spot market. Neither the costs of utility ownership, or more importantly, of the long-term contracts is represented in this model. The contracts negotiated by the state of California were likely a major contributor to reducing market power in the spot market during the summer of 2001, but they were also notoriously expensive.[139] There is much theory to support the notion that the existence of a robust forward market, with contracts freely entered into by suppliers and load-serving entities, will produce more competitive outcomes than would be achieved through the spot market alone. However, I make no attempt here to calculate what the long-term equilibrium of such a forward-spot interaction would yield. These results only indicate that, given a certain exogenously specified level of contracting, spot market outcomes would be more competitive.

Impact of Demand Elasticity

Up to this point, the only source of elasticity in the residual demand function faced by the Cournot producers has been provided by price-responsive import quantities. End-use demand for electricity has been assumed to be perfectly inelastic, reflecting the fact that, outside of the San Diego region, retail rates were frozen during the time period studied. In order to examine the potential impact of price-responsive demand on the market power of producers, in this section I incorporate price-responsive demand into the model. I now represent system demand in the ISO as following a constant elasticity demand function, with an elasticity of -.075. This is somewhat lower than many estimates of the short-run elasticity of demand for electricity, but very few of the available studies have examined an environment in which prices change hourly.[40] Such a response could potentially be achieved by either applying real-time pricing to all customers. To the extent that the underlying potential elasticity of large customers were greater than .075, this figure could also achieved by applying real-time pricing to this more elastic subset of customers.[41]

Figure 6 illustrates the methodology for modeling demand. Whereas before the demand function was the linear function, D_1, demand in this section combines the change in imports (relative to the level observed at the actual PX price) with the change in end-use demand implied by the constant elasticity demand function. For each hour, this function is centered on the point of actual ISO load at a price of \$60/MWh, roughly the energy component of end-use bills during that time. The resulting market demand is therefore, D_2, the combination of the previously utilized linear demand function and the constant elasticity demand function.

Since all demand is assumed to be paying the current wholesale price, the changes introduced by this model therefore combine the effect of time-varying pricing with the effect of an overall increase in the average price. I attempt to separate out these two effects later by also modeling the impact of a rate increase that is applied evenly to all periods, assuming the same .075 elasticity. This latter model therefore shifts overall demand inward, but does not change the slope of the demand function.

The results of these simulations are described in Table 7. The impact of even a modest level of elasticity is substantial when it is applied to the entire system load on an hourly basis. The average wholesale price during this period is reduced from 144.32 $/MWh under the base Cournot simulation to 85.25 $/MWh. By contrast the impact on wholesale prices of the same rate increase (to $85.25/MWh) is minimal when it is applied evenly to all periods. Figure 7 illustrates the relationship between the price impacts and the actual (*i.e.* inelastic) load. The conventional rate increase creates modest savings at high demand levels, but these savings pale in comparison to those achieved under RTP. This highlights the fact that retail rate reform involves much more than simply passing on wholesale prices on a lagged basis. Although a rate increase during this period might have kept the California utilities financially viable, and therefore eliminated the prospect of blackouts, it would not have had a substantial impact on the competitiveness of the market during this period.[42]

4.0 Conclusions

This paper has described the use of competitive assessments in implementing competition policy in the U.S. electricity industry. At the Federal level, these policies have always been driven by the FERC. The Federal Power Act provides the FERC a powerful platform from which it can pursue its policy goals. The complex web of overlapping regulation and jurisdictional battles between the FERC and state regulators does constrain the Commission's ability to develop wholesale power markets in the manner it would prefer. The FERC has limited explicit powers to force structural changes, such as the development of price-responsive consumers and the reduction in supplier concentration. However, the pre-eminent role played by FERC in the approval of electricity mergers and in the granting of market-based rate authority also gives it the ability to influence firms with both carrots and sticks.

In the past, these tools have been employed to encourage firms to undertake various reforms aimed at reducing vertical barriers to competition in the industry. The FERC's current proposals are consistent with this practice. The application of a potentially more restrictive market power hurdle for market-based rate authority, the Supply Margin Assessment, has been restricted to firms that do not participate in ISO supervised markets. This provides suppliers with additional incentive to join ISOs. The FERC's Standard Market Design proposals appear consistent with this trend. The threat of structural changes is being employed as a stick to encourage firms to submit to the regulation of their offer prices and other market power mitigation measures.

But is the carrot leading the mule in the right direction? The focus on ISOs and market power mitigation under SMD creates the danger of confusing ends and means. Competition policy in the U.S. has been predicated on the goal of creating a reasonably competitive environment. By contrast, current policies at FERC have been increasingly focused on regulating behaviors and outcomes. Should a competitive assessment of market structure be used as the stick to implement pricing regulations, or should pricing regulations be used as the stick to encourage structural changes? The answer depends both upon the consequences of the regulations and on the prospects for and benefits of structural change.

I examine this question in the context of the California market. By employing the oligopoly model first developed in Borenstein and Bushnell, I study the ability of oligopoly simulations to recreate actual market outcomes. This gives some indication of the potential value of such models as screens for the impact of horizontal market power. I then utilize the oligopoly model to examine the impact of a hypothetical, less concentrated, California market structure. The results provide some fodder for both sides of the argument. The model indicates that additional divesture of generation units would have yielded a savings of nearly $2 Billion during the 4 summer months of 2000 in California. However, this constitutes less than half of the costs of market power from the current structure indicated by the oligopoly model and by empirical estimates using actual market outcomes. The savings from introducing real-time pricing into the market during this period are even more striking. Even a relatively modest elasticity of .075, when applied to the entire system demand through a dynamic pricing regime, reduces wholesale prices by 40%.

Clearly the gains are substantial, but are they enough to justify a reversal of emphasis away from mitigation measures and towards structural change? The fact that the simulations indicate that non-trivial levels of market power remain even under the structural changes examined gives cause for caution. However, the California market in 2000 is almost universally considered a 'worst-case' scenario for electricity markets. Supply side structural change, when combined with a robust forward market and large end-users with dynamic prices, would go a long way towards obviating the need for most regulation of pricing behavior.

In weighing such changes, we must consider that the benefits likely far outweigh the costs. While the economies of scale of individual generation plants, and of vertically integrated utilities have been extensively studied, there is little evidence about the potential efficiencies to be gleaned, for example, from owning a 6000 MW portfolio as opposed to a 3000 MW portfolio. Dynamic real-time pricing carries the potential for substantial efficiency improvement even if its impact on market power is ignored. The main impediment to such changes appears to be the fact that no institution has the clear mandate or jurisdiction to make them a reality. By virtue of its unique position in directing policies in wholesale markets, the FERC comes the closest. The results in this paper indicate that the FERC should reconsider its emphasis on pricing regulation and direct more of its focus to being an agent for structural change.

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Appendix: A Cournot Model of the California Electricity Market

In this appendix, I describe the model and assumptions used to generate the results of Section 3. The model is described in more detail in Bushnell (2003). The Cournot model utilized is based upon that of Borenstein and Bushnell (1999). It uses an iterative global search algorithm to calculate the profit maximizing best response output quantity for each firm. At each iteration, the optimal output level for a given firm is calculated, holding constant the output levels of the other strategic firms. The process iterates through each strategic firm, and then repeats itself. ACournot-Nash equilibrium is found when each firm, given the output levels of the other firms, does not change its output. The model of Borenstein and Bushnell was adjusted to incorporate the hourly market data from the California market. These data are drawn from Borenstein, Bushnell, and Wolak (2002).

Market Demand

As in BBW, the Cournot simulation models competition for the residual demand served by fossil-fired generation plants located within the California ISO system. All of the divested generation plants fall into this category. This residual portion is equivalent to the total ISO system demand less the output from hydro and geothermal resources, as well as from must-take resources operating under regulatory or contractual arrangements. Supply from units in this latter category is assumed to be inelastic as the majority of the revenues earned by these plants were not tied to market prices. End-use demand is assumed to be inelastic.

Imports into the California ISO comprise the source of residual demand elasticity faced by the Cournot producers within the ISO. In BBW, the import elasticity is taken from the day-ahead adjustment bids of import schedules. While these bids constitute a reasonable estimate of the overall responsiveness of imports to price changes in a given hour, it is not reasonable to expect that the depth of that import supply curve represents the overall availability of import capacity into the California ISO. This is because the day-ahead adjustment bids only represent offers into the day-ahead markets, while there were other venues for trades, most notably the ISO real-time market.

To integrate the import responsiveness from BBW into a Cournot simulation, I derive an hour-by-hour slope of the import demand curve from the measured change in import quantities and the change in price between the actual market outcomes and the counter-factual competitive outcome estimated in BBW. [43] I then derived a linear residual demand curve for each hour by applying that slope to a linear demand curve running through the observed actual market price and quantity.[44] The statistics on these import calculations are summarized below.

As Table 8 illustrates, taking the import slopes from the BBW calculation yields a few extremely small and large values. In fact there were approximately 40 hours in which the BBW results implied a negative slope. These extreme results were all the result of extremely small changes in either price or import quantity (or both) in the BBW calculation for that hour. Since the calculated changes in price and import quantity are both the average of the results of 100 monte-carlo iterations, aberrant values can result in individual hours where the price change was small. As one would expect, these extreme slopes produced extreme values for both the Cournot and competitive prices. Since these are driven by the import slopes and not by the underlying model, I report only the results for hours where the calculated import slopes were between -1 and -1000 MW/$. These account for 2790 of the possible 2928 hours in the study period. The main distinguishing feature of the dropped hours is that they were low-price, competitive hours. The mean PX price in the dropped hours was about $55/MWh (as opposed to $128/MWh for the full sample) and the mean estimate of the margin over the competitive price from BBW for those hours was less than $2/MWh (as opposed to $62/MWh for the full sample).

Thermal Generation

The marginal costs of thermal generation units are modeled exactly as they were in BBW. Unit average heat rates (Mbtu/kwh) are multiplied by appropriate fuel prices ($/Mbtu) that are updated daily for natural gas and monthly for petroleum-based fuels.

Where appropriate, emission rates for NOx are multiplied by the monthly average price for NOx emissions credits.[45] Unit variable operating and maintenance expenses are the same as in BBW. The generation capacity of each unit is reduced according to its forced outage factor, effectively reducing the available capacity of each unit by the same level in each hour. This is in contrast to BBW, where unit availability was modeled using monte-carlo simulation draws for each hour using the same respective forced outage factors for each unit.

[*] University of California Energy Institute. Email: Bushnell@Haas.Berkeley.edu. I wish to acknowledge the helpful comments of Severin Borenstein, James Griffin, Alvin Klevorick, Steve Puller, Frank Wolak and participants at the Texas A&M Bush School Electricity Deregulation conference.

[1] Joskow (1997) describes the evolution of the industry and its regulatory institutions.

[2] Under section 206(a) of the FPA, if the FERC finds, after hearing, that rates are "unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, practice, regulation, or contract to be thereafter observed in force, and shall fix the same by order."

[3] A recent bill introduced to Congress would take away FERC's authority to review mergers.

[4] While it reserves the right to pursue an independent policy, the U.S. Dept. of Justice antitrust division has traditionally allowed FERC to play the lead role in the review of electric utility mergers. When the antitrust division has gotten involved in an electricity merger, it is usually as an interested party intervening in the FERC proceeding.

[5] See FERC (1996), Order 592. This chapter will focus on policies dating from the mid 1990s. See Frankena and Owen (1994) for a description of merger policies before this time.

[6] Joskow (1999) describes FERC's historical approach to merger analysis and the adoption of the 1996 policy statement in the context of the proposed merger of BG&E and PEPCO.

[7] See Frankena (2001).

[8] See Scwheppe, et al. (1982).

[9] See the comments of EEI (1998), and WEPCO/PHB (1998).

[10] See, for example, Borenstein, Bushnell, and Knittel (1998).

[11] Several theoretical papers have examined this phenomenon. See Borenstein, Bushnell, and Stoft (2000),Cardell, Hitt, and Hogan (1997) and Joskow and Tirole (2001).

[12] The HHI measures the sum of the squared market shares of all the suppliers in the market. The convention is to multiple the resulting sum by 10,000. Thus, for example, a market with 4 equal sized producers would yield a HHI of $4 * 0.25^2 * 10{,}000 = 2{,}500$.

[13] See for example, the 1998 order accepting market-based rates for AES facilities in California (FERC, April 1998).

[14] See FERC (September, 2001).

[15] See Massey (2000).

[16] See FERC (December, 2000).

[17] See AEP, November 2001.

[18] IBID

[19] See, for example, Morris (2002) and Hieronymus (2001).

[20] See Morris (2002).

[21] For example, regulations exist in all of the ISO supervised markets to limit the offer prices of firms with 'local' market power conveyed upon them by transmission network constraints. In some circumstances, these constraints can bestow monopoly power on specific generation units or firms.

[22] See Blumstein, et al. (2001) for a full review of the California restructuring process.

[23] See FERC (December 2000).

[24] The FERC order of March 9, 2001 (FERC, March 2001) outlined a calculation that essentially set a maximum allowed offer price according to a formula that applied updated gas and emission cost indices.

[25] See FERC (November 2001b)

[26] See, for example, Williams (2002).

[27] See, for example, SMUD, et al. (2002).

[28] FERC Docket No. EC95-16-000.

[29] The model is described in several filings in the case. See, for example, Koch (1996).

[30] See Borenstein, Bushnell, and Knittel (1998a) and (1998b).

[31] The proposed Western Resources – KCP&L merger as well as the merger between Ameren Corp. and Central Illinois Light Co. are both mergers between traditional vertically integrated regulated utilities.

[32] For a general overview of basic oligopoly models, see Carlton and Perloff (1990).

[33] The other equilibrium concept that is frequently applied to electricity markets allows firms to specify a full supply function (i.e. a function specifying different price-quantity combinations) of either a general or specific functional form. Supply function equilibrium have been applied to the UK market by Green and Newbery (1992) and Green (1998). Supply function models are also used by Rudkeivich, et al. and Baldick, Grant, and Kahn (2000).

[34] Borenstein, Bushnell, and Stoft (2000), and Borenstein, Bushnell, and Knittel (1998a) simulate the impact of market power on congestion in California and New Jersey, respectively. Day, Hobbs, and Pang (2002) simulate market power and congestion in the England and Wales market.

[35] As the transition periods in those other markets expire, the incentive effects of vertical integration will change. Currently most of those companies are operating under retail price freezes similar to those imposed in California during its transition period. It is largely expected that once these rate freezes expire, distribution companies obligated to serve their retail customers will be allowed to pass on increases in wholesale electricity costs. At that point, the impact of retail obligations on mitigating the incentives of vertically integrated generation companies to raise prices will be removed.

[36] See BBW (2002) for the details on the derivation of a residual demand function faced by strategic suppliers.

[37] See Wolak (2002) for a description of the impact of long-term contracts on the incentives of generation unit owners.

[38] In the simulation, this capacity was treated like the import capacity described in equation 1. The production from all these price-taking units at a given price was subtracted from the residual demand curve of the remaining Cournot firms.

[39] See Wolak (2003).

[40]Bushnell and Mansur (2002) find a reduction in consumption of around 7% in the San Diego region during a period in which rates roughly doubled, implying an elasticity , of around .07. Although I assume hear that elasticity does not vary by time-of-day, it should be noted that Bushnell and Mansur find a somewhat larger reduction in demand during peak afternoon hours.

[41] See Borenstein (2003) for a detailed discussion of dynamic pricing regimes.

[42] To the extent that the presence of financially solvent utilities would have limited the chaotic market conditions seen during the following winter of 2000-2001, an earlier rate increase may have improved competitiveness somewhat during this latter period. See Wolak (2003) for a description of the California crisis during this time period.

[43] As described in BBW, the market price used is the day-ahead unconstrained price from the California Power Exchange (PX). The market quantity is the residual demand served by thermal generation within the ISO and imports into the ISO.

[44] I also tried applying a constant elasticity demand curve, but this produced extremely aberrant results for some hours. The aggregate import supply curve more closely resembles a linear function.

[45] Generation units in the South Coast Air Quality Management District (SCQAMD) are subject to the RECLAIM emissions credit trading program for NOx emissions.

	fossil	hydro	nuke	other	TOTAL
AES	3921				3921
Calpine	487			621	1108
Duke	2639				2639
Dynegy	1635				1635
PG&E	3456	3878	2160	793	10286
Reliant	3698				3698
SCE		1164	2150		3314
SDG&E	1988				1988
QF & Other	6130	5620		4267	16017
TOTAL	23953	10662	4310	5680	44605

Table 1: Generation Ownership (MW) in California ISO - July 1998

	fossil	hydro	nuke	other	TOTAL
AES	3921				3921
Calpine	487			621	1108
Duke	3343				3343
Dynergy	2871				2871
PG&E	618	3878	2160	793	7448
Reliant	3698				3698
SCE		1164	2150		3314
Mirant	2886				2886
QF & Other	6130	5620		4267	16017
TOTAL	23953	10662	4310	5680	44605

Table 2: Generation Ownership (MW) in California ISO - June 2000

	observations	mean Cournot price ($/MWh)	mean PX price ($/MWh)	mean Competitive price ($/MWh)
June	699	127.93	122.29	52.67
July	704	131.84	108.60	60.27
August	724	185.02	169.16	79.14
September	696	116.26	116.64	75.12

Table 3: Cournot Simulation and Actual PX Prices - Summer 2000

	Actual		Counter-factual	
	MW	**HHI**	**MW**	**HHI**
AES	3921	550	1873	126
Dynegy	2871	295	1165	49
Duke	3343	400	1585	90
Mirant	2886	298	2886	298
Reliant	3698	489	2306	190
SDG&E units	*NA*	*NA*	1407	71
Alamitos	*NA*	*NA*	2048	150
Ormond	*NA*	*NA*	1271	58
Moss	*NA*	*NA*	1474	78
South Bay	*NA*	*NA*	704	18
	16718	**2032**	16718	**1126**

Table 4: Actual and Hypothetical Thermal Ownership

	Cournot ($/MWh)	Divest to Cournot ($/MWh)	Contract/Divest to Fringe price ($/MWh)	Competitive Price ($/MWh)
June	127.93	98.40	88.95	52.67
July	131.84	102.09	89.99	60.27
August	185.02	144.18	126.63	79.14
September	116.26	91.30	78.74	75.12

Table 5: Price Impacts of Divestiture

	Total Cost Cournot $ Million	Total Cost Divest to Cournot $ Million	Total Cost Savings $ Million
June	1870	1410	466
July	1830	1420	415
August	2800	2190	605
September	1570	1230	341
Total	8070	6250	1827

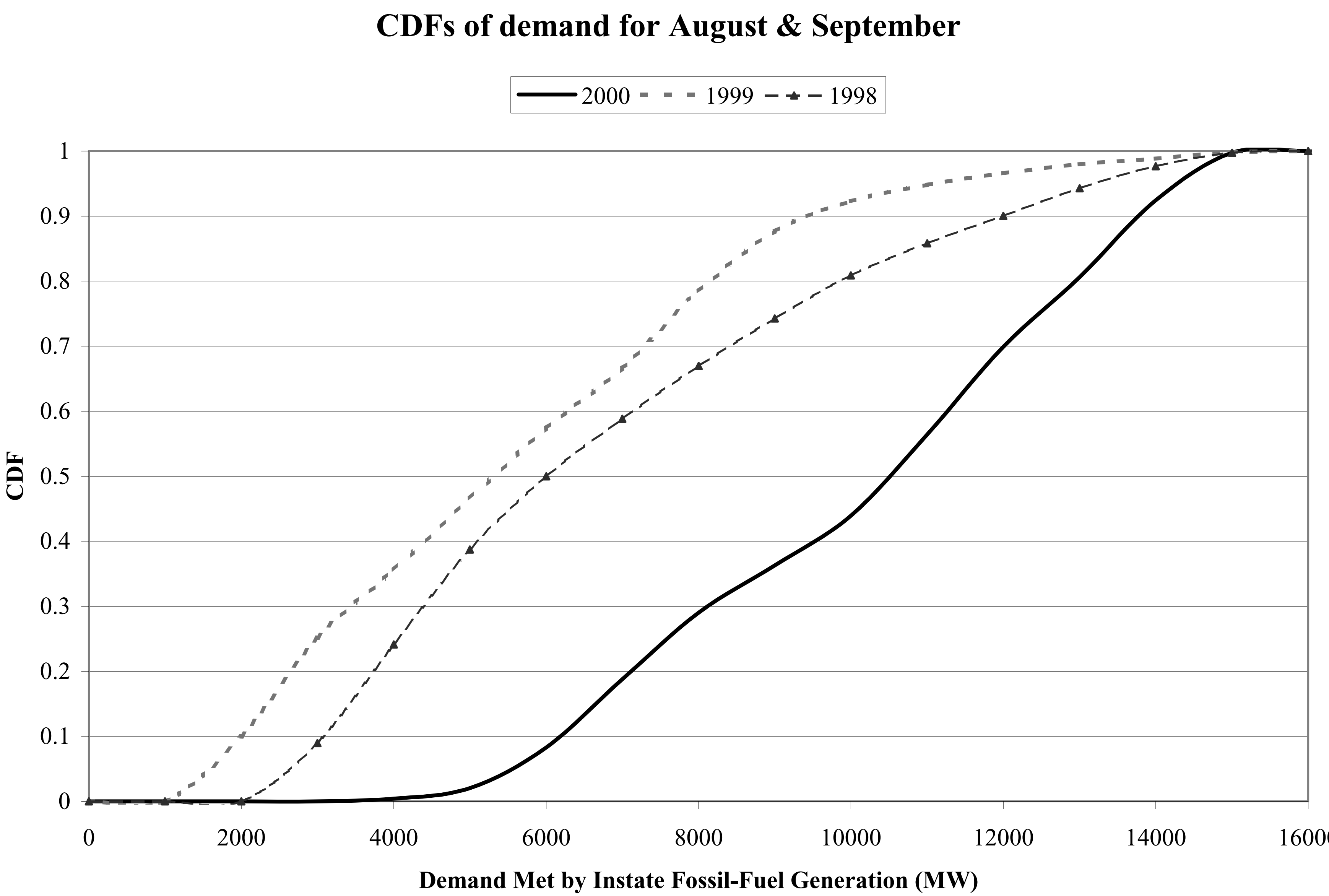
Table 6: Market Savings from Further Divestiture

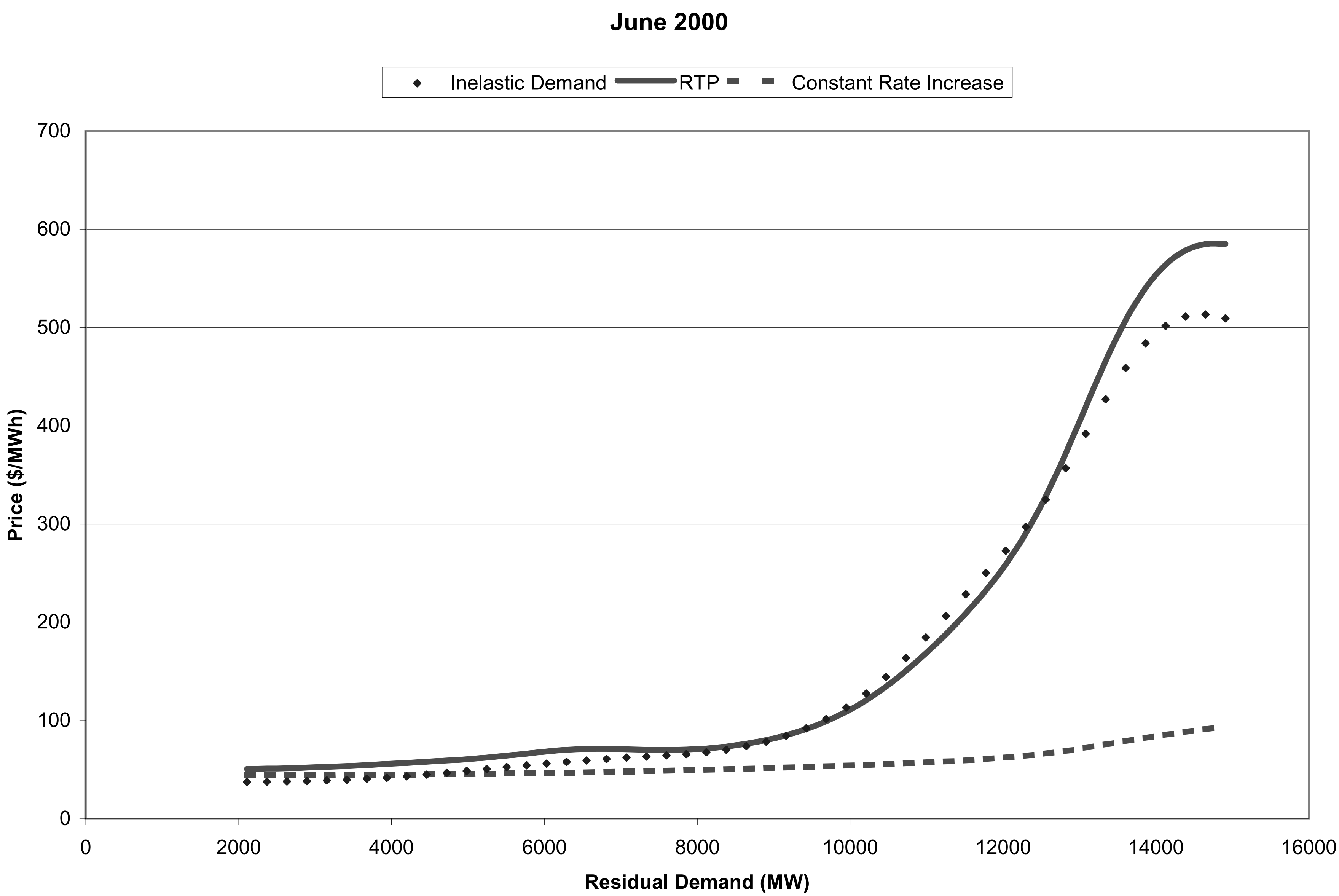
	Inelastic Demand ($/MWh)	Real-time Pricing ($/MWh)	Constant Rate Increase ($/MWh)
June	127.93	72.47	122.26
July	131.84	79.04	124.23
August	185.02	107.98	175.15
September	116.26	80.66	107.21

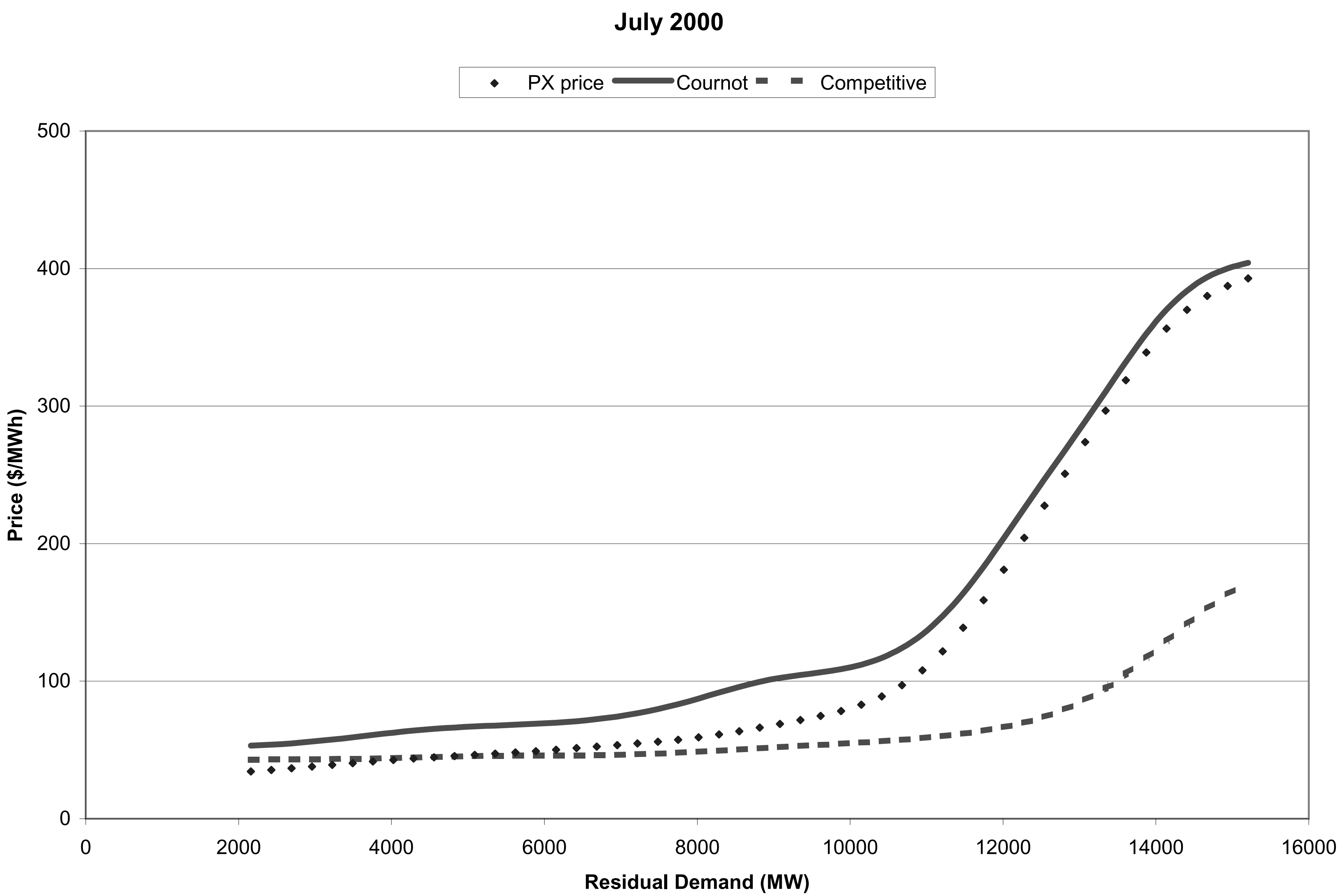
Table 7: Price Impacts from Changes in Retail Rates

	Actual	*Slope (-ΔMW/Δ$)*			
	Net Imports	***Mean***	***Median***	***Min***	***Max***
June	3943	153.89	61.74	1.7E-13	2.9E+04
July	3321	70.63	40.24	4.0E-14	2.7E+03
August	3096	36.91	18.66	1.1E-12	1.8E+03
September	4240	57.88	26.15	3.4E-04	2.2E+03

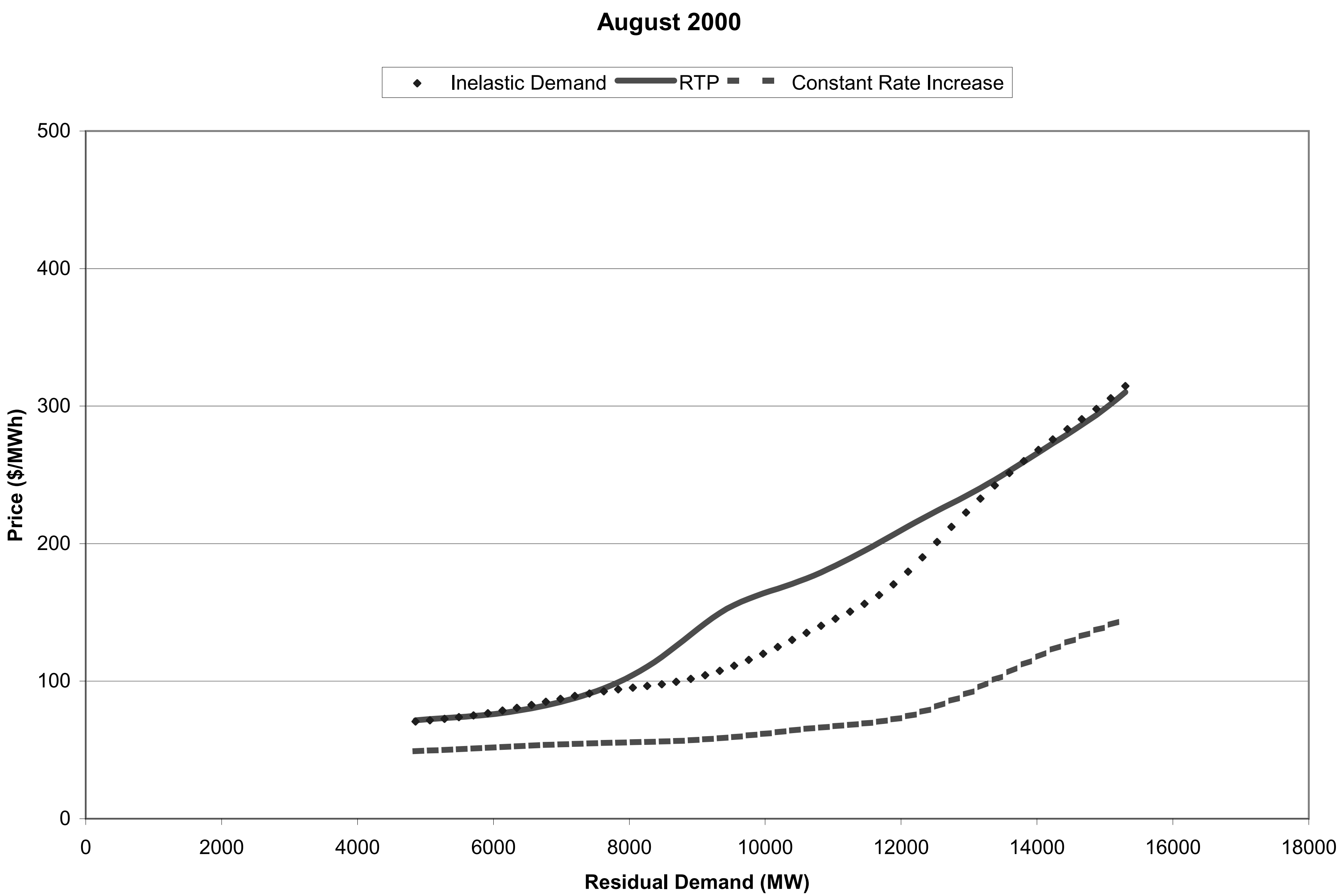
Table 8: Import Summary Statistics

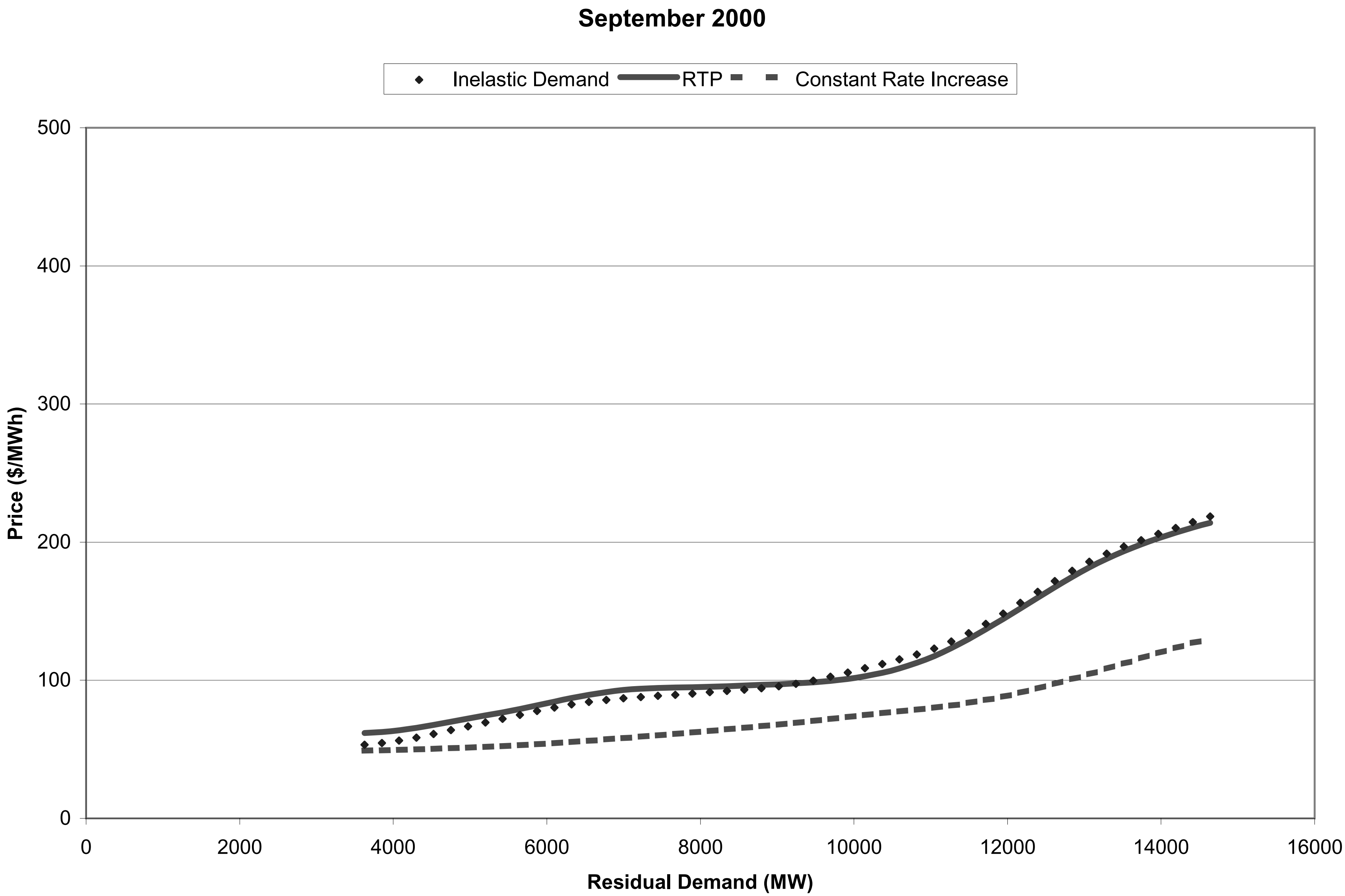

CDFs of demand for August & September
2000
1999
1998
CDF
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
2000
4000
6000
8000
10000
12000
14000
16000
Demand Met by Instate Fossil-Fuel Generation (MW)

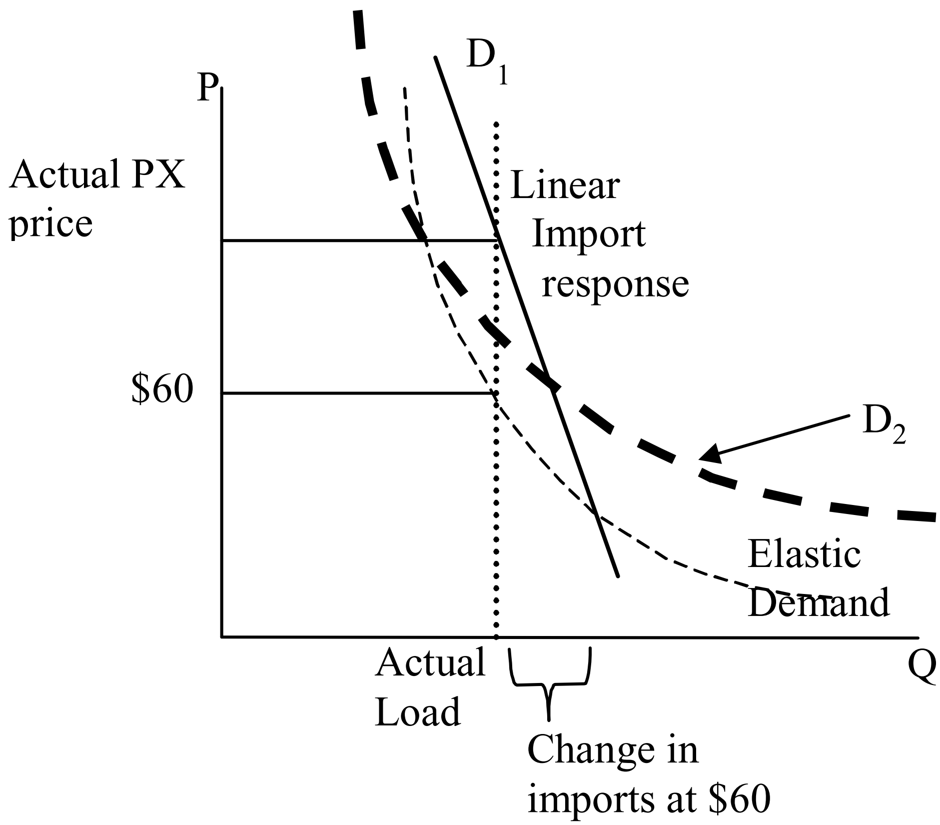

June 2000
Inelastic Demand
RTP
Constant Rate Increase
Price ($/MWh)
Residual Demand (MW)
0
100
200
300
400
500
600
700
0
2000
4000
6000
8000
10000
12000
14000
16000



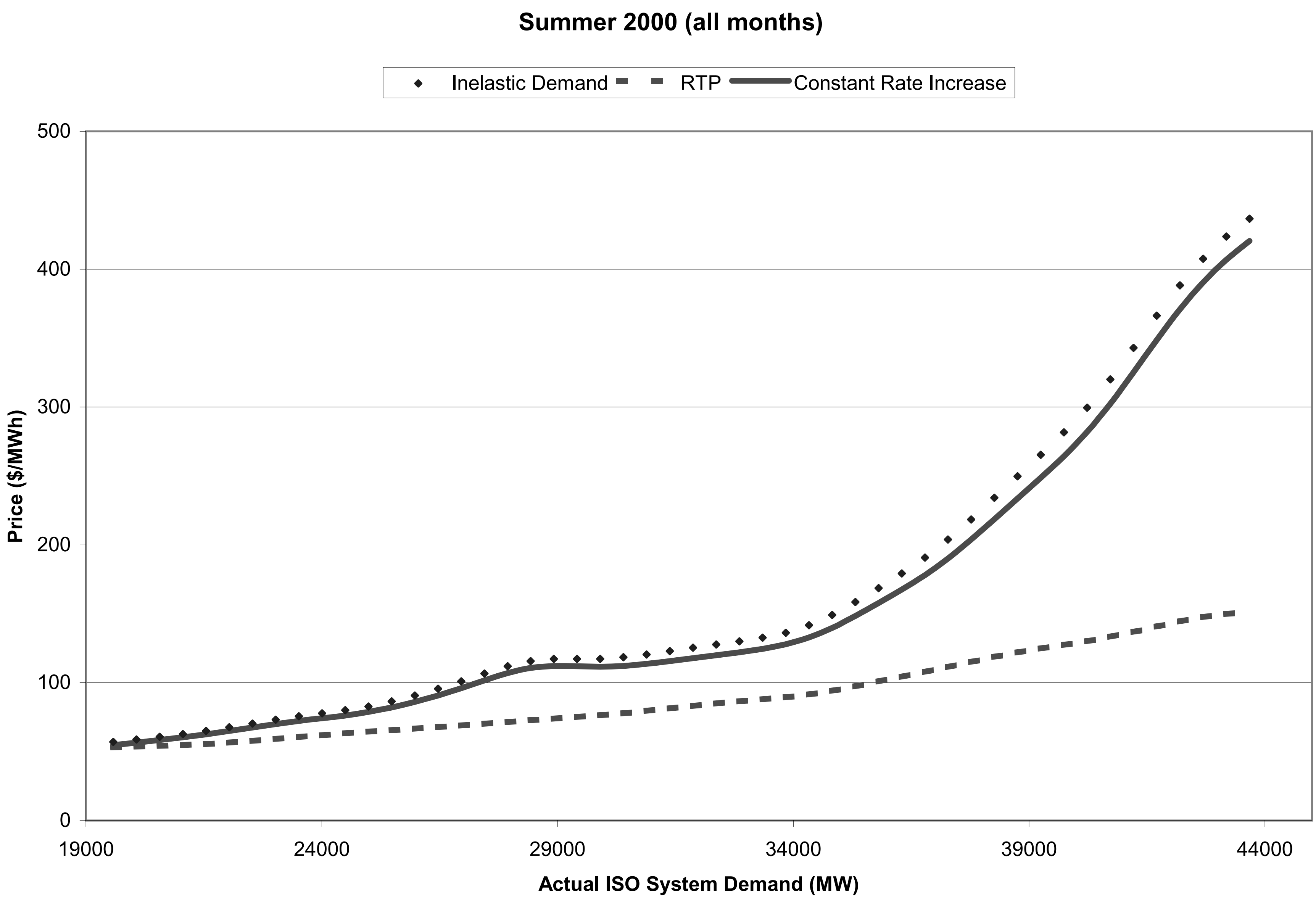
July 2000
PX price
Cournot
Competitive
Price ($/MWh)
Residual Demand (MW)
0
100
200
300
400
500
0
2000
4000
6000
8000
10000
12000
14000
16000


August 2000
Inelastic Demand
RTP
Constant Rate Increase
Price ($/MWh)
0
100
200
300
400
500
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
Residual Demand (MW)


September 2000
Inelastic Demand
RTP
Constant Rate Increase
Price ($/MWh)
500
400
300
200
100
0
0
2000
4000
6000
8000
10000
12000
14000
16000
Residual Demand (MW)



P
Actual PX price
$60
D1
Linear Import response
D2
Elastic Demand
Q
Actual Load
Change in imports at $60



Summer 2000 (all months)
Inelastic Demand
RTP
Constant Rate Increase
Price ($/MWh)
500
400
300
200
100
0
19000
24000
29000
34000
39000
44000
Actual ISO System Demand (MW)