Performance Review of Electric Power Markets

Kenneth Rose
Senior Institute Economist

Selina Lim
Venkata Bujimalla
Graduate Research Associates

Review Conducted for the Virginia State Corporation Commission

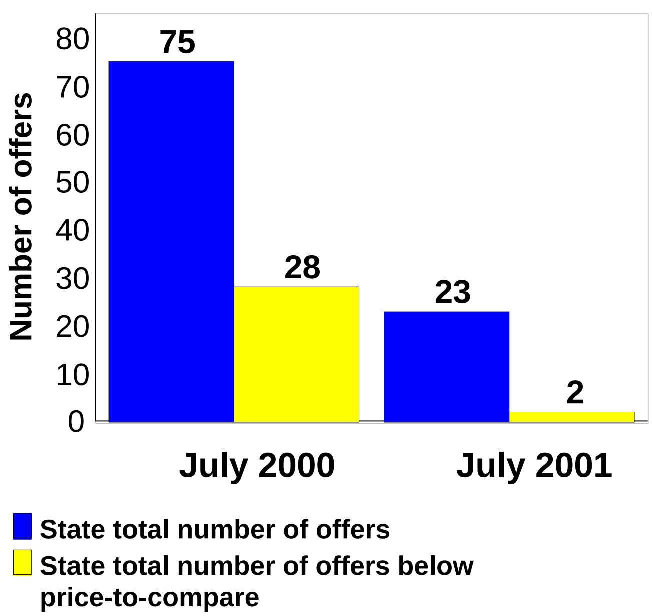
The National Regulatory Research Institute
The Ohio State University
1080 Carmack Road
Columbus, Ohio 43210
Phone: 614-292-9404
Fax: 614-292-7196
www.nrri.ohio-state.edu

August 31, 2001

EXECUTIVE SUMMARY

Fifteen states and the District of Columbia allow retail access at this time and three more states, Michigan, Texas, and Virginia, plan to begin January 2002. While no state has had the magnitude of problems that California has had, the move to competition in retail electric markets has been slowed considerably. Six states that passed electric restructuring legislation have decided to postpone the move to allow retail access,[1] and at least 14 states that have not passed restructuring legislation have decided to discontinue considering the issue at this time.[2] No state has passed restructuring legislation since the California meltdown began last summer and no state appears to be ready to do so soon.

Fig. ES 1. Pennsylvania statewide residential offers



Higher prices and volatility in wholesale markets across the country have taken their toll on state retail markets. At this time, no western state has an active retail market and in the east, states that appeared to be working well initially have shown signs of stress. Pennsylvania, which is often regarded as the most successful restructuring state, has seen both the number of competitive residential offers and customer load (for all customer classes) served by alternative suppliers plummet to new lows (Figures ES 1 and ES 2). New Jersey, which used a similar approach to restructuring as Pennsylvania, has seen its retail markets also

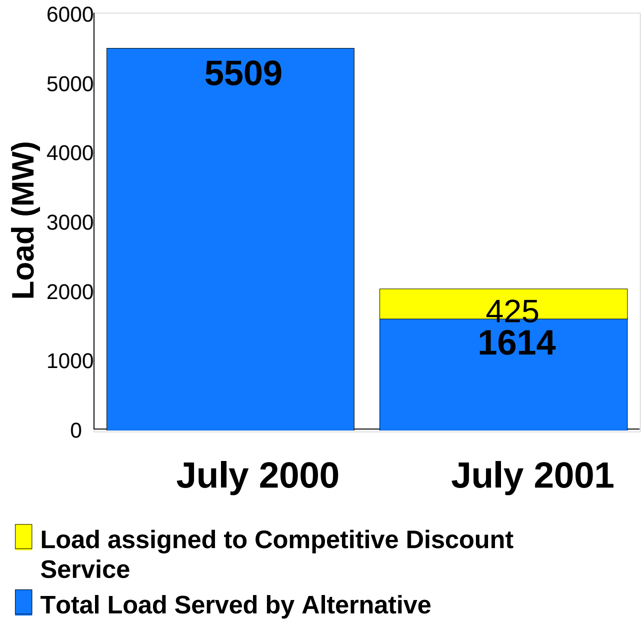
---

[1]Specifically, Arkansas, Nevada, New Mexico, Oklahoma, Oregon, and West Virginia have all decided to delay, to either a newly specified date or indefinitely.

[2]The 14 states that are not considering or are no longer considering electric restructuring at this time are Alabama, Alaska, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Mississippi, South Carolina, South Dakota, Utah, Wisconsin, and Wyoming.

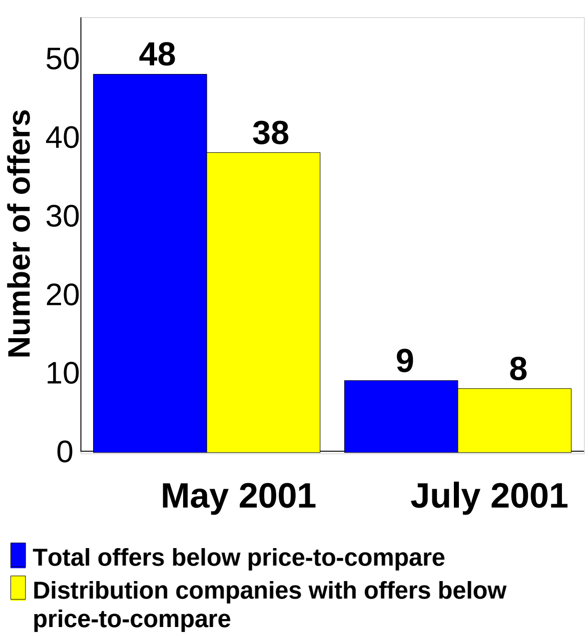
dwindle considerably. Nationwide, from a survey of 13 of the states and the District of Columbia, in which retail access is now allowed, it was found that in May of this year, there were 38 distribution companies with at least one competitive residential offer priced below what a customer would pay if they stayed with their utility (Figure ES 3). By July, however, that number had shrunk to just eight distribution companies whose customers had such offers.

Fig. ES 2. Pennsylvania total load served by alternative suppliers



There is clearly a very strong link between retail market performance, and the problems these markets have been experiencing, and the wholesale market. This is because most retail markets have overall price constraints and seldom fluctuate concurrently with changing conditions in the wholesale market. The retail standard offer, or the "price to compare," is the price for generation service paid by a retail customer who does not select a competitive supplier. The price to compare is a benchmark that not only informs customers to allow them to make a selection, but is also an indicator for use by competitive suppliers that are considering entry into or whether to remain in a retail market.

Fig. ES 3. Residential offers nationwide



The effect of the retail price constraints depends on the amount of the available "headroom," the difference between the generation price to compare (the price for continued distribution company service) and the cost to competitive suppliers to procure (by purchase in the wholesale market or from their own generation source) and market the power to serve retail customers. If there is sufficient headroom, suppliers are able to offer customers an opportunity to save and can entice customers away from the standard offer or price to compare. However, the headroom may be too small to cover all the costs of supplying the retail customers or even negative–that is, where the cost of securing power and delivering power to the retail customer exceeds the constrained retail price. The degree to which rising wholesale prices have occupied any available headroom is the primary reason that retail markets, after a period of initial success in some states, have recently begun to decline and why some other markets have seen very little activity to date.

As noted, most retail prices are not designed, nor intended to, perfectly track wholesale market price fluctuations. The price to compare is usually a component of an overall fixed or “bundled” price made available during a transition period that will, among other things, provide protection to retail customers from unexpected price increases, allow the incumbent generator to collect any costs that may be uneconomic (or “stranded”) in a competitive market, and allow time for a competitive wholesale market to develop. The price-to-compare is generally fixed, with periodic adjustments based on prior agreements, automatically adjusted for changes in fuel costs, or is changed through an administrative process. Some areas with relatively high prices also built in discounts that generally ranged from 5 percent to 15 percent of the overall retail price customers were paying before restructuring.

Residential retail market performance is measured in terms of the number of offers being made to residential customers, the potential savings opportunities these offers present, the number of suppliers in the area, the type of offers being made, and the percent of customers that selected an alternative supplier, among other factors. Since these performance measures are highly dependant on prices in the wholesale market, retail market performance cannot be viewed in isolation, but should be considered alongside an analysis of wholesale market performance as well.

Higher wholesale prices alone, while perhaps causing a problem in retail markets, would not necessarily indicate a poorly functioning market. Rather, wholesale market performance should be analyzed in terms of how closely actual prices have been tracking what would occur in a fully competitive market. Wholesale prices may increase because of higher input costs (such as from higher natural gas prices), a scarcity of supply capacity (from increased demand or loss of existing capacity for example), or because suppliers are able to raise and maintain the price above a competitive level. If the high prices are due to input costs or scarcity, then, over time as new capacity is added, for example, it may correct itself and may not require any policy adjustments. If it is the suppliers’ ability to exercise a degree of price control, however, then there is a problem in the wholesale market and corrective action may be necessary.

This ability to control the price, rather than it being determined by the competitive process, is referred to as market power. If supplier market power is relatively modest or is not expected to persist for an appreciable amount of time, then no intervention may be warranted (and may even be harmful). A relatively small degree of market power is not unusual, even in markets most would regard as competitive. Unfortunately, the evidence suggests that wholesale electricity markets are having problems with suppliers being able to control, to some significant degree, the market price. The degree of market power that a supplier can exercise is a function of the characteristics of electricity and its delivery system to customers. These characteristics also suggest that market power can be considerable in electricity markets and may persist for a long time.

These characteristics include that (1) demand for electricity is very inelastic (a percentage change in price results in a relatively smaller percentage change in the quantity demanded), particularly in the short-run since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers; (2) markets are very concentrated for most geographic regions, even for multi-state wholesale regions; and (3) market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Since these factors are inherent in the characteristics of electric generation and delivery, they are generally difficult to remedy and, in large measure, beyond the control of policy makers.

In general, suppliers can exercise market power using two primary strategies. First, they can physically withhold capacity from the market. This causes higher marginal costs units to be dispatched and the market price to rise correspondingly. This results in more revenue for the plants that are dispatched than they would have received without the withholding of capacity and more than makes up for the lost revenue from the plants withheld. Second, suppliers can economically withhold capacity. In this case, the supplier bids a very high price for the plant or unit, causing the plant to be dispatched at a price much higher than its marginal cost or it not being dispatched at all (resulting in a supplier benefit similar to physical withholding). In a perfectly competitive market, these methods would be counterproductive since with many suppliers, relatively easy entry into the market by new suppliers, and suitable and readily available alternatives for customers for the product, supplier attempts to withhold would be undercut by competitors or customers seeking alternatives. For this reason market power is negligible or nonexistent in a fully competitive market. The source of the market power in electric markets stems directly from the three characteristics noted above. For these strategies to be successful, it is *not* necessary for clearly illegal activity such as collusion or price fixing to occur.

Since growing demand in California could not be readily matched with additional supply, there is little doubt that scarcity played a role in the California crisis. What would be expected is that the price would be driven up to the marginal cost of the highest cost marginal unit needed to satisfy demand–a higher marginal cost than would obtain than during times of relatively plentiful supply. However, the actual price exceeded, often greatly exceeded, the expected higher marginal cost.

There is evidence that suggests that even before the summer of 2000, market power was significant in California, particularly during peak hours. There are several analyses of the California market that present evidence of substantial market power during the recent crisis. An analysis by the Chairman of the California Independent System Operator's (ISO) Market Surveillance Committee estimated that, for the period of June 2000 through January of 2001, the average markup (as a percentage of price) was 45 percent and peaked during this period at 64 percent of the price in August. In dollar terms, the largest markup occurred in January of 2001 at $130/MWh above the expected competitive price–when the average monthly price was $305/MWh.

For the PJM ISO region, one independent analysis found that market imperfections in the PJM spot energy market (which account for 10 percent to 15 percent of the market) for the period April through August of 1999 totaled $224 million. This study estimated that about 30 percent of the price in the spot energy market was a markup above what would have occurred with perfect competition. When bilateral contracts are added (an additional 30 percent of the market) the sum of the spot market and bilateral contract costs is $827 million above the perfect competition level, or 32 percent of the price being markup over competitive prices. This considerably exceeds estimates made by PJM's Market Monitoring Unit, which estimated an average markup of about 2 percent for April through December of 1999 and a yearly maximum markup in July of 8 percent. One explanation for this difference may be different calculation methods and data access.

Similar analyses have not been conducted of the New York and New England ISO regions. However, there is evidence that suggests suppliers in these markets may also have considerable market power, based on supplier behavior. For other regions of the country that do not have organized spot markets or access to thorough information, it is much more difficult to determine how well markets are developing. Some limited price information may be available through price indices and futures markets. However, these may not present a complete picture of market transactions or provide enough data for a reliable estimate of market power. Both economic theory and common sense suggests that a lack of reliable information may simply invite mischief and delay needed changes to reduce market power and thereby improve the health of the market. Considerable consumer harm may be the consequence.

Since an attempt is being made to develop competitive markets to replace decades of state and federal regulation, it is generally assumed that these markets will require both time to develop and frequent adjustments when problems are encountered. It is unlikely that idealized, perfectly competitive markets will develop immediately. Since these markets began relatively recently, and the transition period continues for most areas, markets are still evolving. Over time, as new generating capacity across the country comes on line wholesale prices may moderate and retail markets may be able to get back on track. However, given the characteristics of electricity demand, supply, and the concentrated nature of power markets, supplier market power may be both significant and persist for years to come.

Table of Contents

List of Tables

List of Figures

Part I: Status of Electric Retail Markets

Introduction

Competitive wholesale markets have been developing since the late 1980s with the beginning of “voluntary” open access; however, power sales between utilities and other resellers of electricity began decades before that as transmission interconnection developed. Part II of this report reviews the performance of several regional wholesale markets that have highly developed organized markets and have had comprehensive analysis conducted of them. In contrast, retail markets where retail access is allowed, that is, where end-use customers are allowed to choose their own supplier, are a relatively new development. The first states passed electric restructuring legislation in 1996, and in 1997 several states began pilot or phase-in programs. The first states that permitted retail access for all retail customers of regulated investor-owned utilities did so beginning in 1998. Several of these beginning states’ developments are reviewed in detail later in this section.

How can retail market performance be measured?

Wholesale market performance is discussed in the next part of this report in terms of prices and how closely actual prices have been tracking what would occur in a fully competitive market.[1] The actual prices paid by retail customers that choose a competitive supplier is not made public. Measuring an actual price trend, and the potential benefits to consumers, is therefore not directly observable. The review of retail markets in this section summarizes what we can observe in the markets, in terms of offers being made to residential customers, the potential savings opportunities these

---

[1]As is discussed in detail in Part II, this means a negligible amount of market power is being exercised by suppliers. Basically, this means that market prices are at the marginal cost of the marginal unit needed to serve electricity demand at that time period.

offers present, the number of suppliers in the area, the type of offers being made, the percent of customers that have selected an alternative supplier, among other factors.

These potential performance indicators in isolation do not determine whether a retail market and its design is succeeding or failing. Rather, considered in tandem with an assessment of wholesale market developments in Part II of this report, these indicators present a picture of how retail markets are evolving. Since these markets began relatively recently, and the transition period continues for most areas, markets are still evolving. Therefore, the purpose of this report is not to judge success or failure of competition overall, but to present facts to assess the state of retail and wholesale markets today.

Retail market performance is highly dependant on prices in the wholesale market. This is because most retail markets have overall price constraints and seldom fluctuate concurrently with changing conditions in the wholesale market.[2] The retail standard offer, or the "price to compare," is the price for generation service paid by a retail customer who does not select a competitive supplier. These customers continue to receive power through their distribution company, where it is supplied by the distribution company that still owns generation, an affiliated generation owner, an unaffiliated supplier or suppliers, or some combination of all of these generation sources.

The standard offer or price to compare is the benchmark or "price to beat" not only to inform customers to allow them to make a choice, but is also an indicator for use by competitive suppliers that are considering entry in to a retail market. The effect of the retail price constraints depend on the amount of the available "headroom," which is the difference between the generation "price to compare" and the cost to procure power to serve retail customers. If there is sufficient headroom, suppliers are able to offer

[2]A survey conducted in June of 2000 by NRRI on how the standard offer is determined and adjusted found that, of the 13 states that responded to the survey, only three distribution companies had rates that were not capped or frozen at that time. One of these companies, San Dieago Gas & Electric, had a cap subsequently reapplied after wholesale prices soared in California. The other two were in New York state, Consolidated Edison and Orange and Rockland Utilities.

customers an opportunity to save and can entice customers away from the price to compare.[3] However, the headroom may be too small to cover all the costs of supplying the retail customers, be nonexistent, or even negative–that is, where the cost of securing and delivering power to the retail customer exceeds the retail price.[4] As will be seen, this lack of headroom is the primary reason that retail markets, after a period of initial success in some states, have recently begun to show signs of stress and why some other markets have seen very little activity to date. A numerical example of this effect is presented in Part II, in the discussion of the PJM wholesale market.

---

[3]Of course, as demonstrated by the success of "green" suppliers, who offer power generated to some degree by renewable or "clean" energy resources, price is not the only consideration customers use to select a supplier. Other factors include reliability, fuel source, and contract terms. While customers are willing to pay a premium for these other factors, price is still the dominant consideration for most customers.

[4]An extreme example of negative headroom is California, where it has led to the filing for bankruptcy protection of at least one distribution company (PG&E) and financial difficulties for another. Distribution companies in other states, for example, Massachusetts and Pennsylvania (GPU), have received upward adjustments to the standard offer price to recover the increased cost of obtaining power in the wholesale market (made necessary because the distribution companies sold their capacity). In the Pennsylvania/GPU case, a settlement reached in June of 2001 allows GPU to defer for ratemaking and accounting purposes the difference between what it can charge customers for generation under the rate cap and its actual cost to supply electricity. The deferral provision of the settlement allows GPU to retain unrecovered generation costs on its books until 2010. Overall customer rates will not increase (the rate cap was extended through 2007), but the "shopping credit" or price to compare will increase. The settlement ends the Competitive Transition Charge (CTC) in 2015. GPU stated that it lost $47 million on electricity supply in Pennsylvania in 2000 and estimated it would lose an additional $250 million in 2001 without rate relief.

Overview of Status of Retail Access

The following sections provide an overview of the status of state restructuring and retail access. Specific states and regions that share the general geographic region with Virginia are then briefly summarized. A more comprehensive look is taken at four states that were early implementors of retail access and, consequently, have considerable experience to date: California, Massachusetts, New Jersey, and Pennsylvania. This is followed by a summary of activities in Ohio, two northeastern states, and three western retail markets. The Appendix at the end of the report summarizes the retail market activity during May and July of this year in 13 states and the District of Columbia. This includes all states that currently allow retail access except Illinois[5] and New Hampshire that began full retail access on May 1 of this year.

Overview of State Electric Restructuring Activities

Currently, 15 states and the District of Columbia allow retail access and three more states plan to allow it soon (Figure 1 and Table 1). Along with Virginia, which plans to allow retail access beginning January 2002, Michigan and Texas also plan to begin full retail access at the same time. Six states that passed an electric restructuring law, however, have opted to delay restructuring. Specifically, Arkansas, Nevada, New Mexico, Oklahoma, Oregon, and West Virginia have all decided to delay, to either a newly specified date or indefinitely. West Virginia, discussed in more detail below, had a long transition period to full retail access, but has not proceeded to implement its restructuring law and is not expected to soon. While the issues and motives may differ in each of these states, in general they believe that the delay would allow them time to observe how restructuring states are doing and plan accordingly. In addition, it may also provide time to build any required power infrastructure (generation and transmission) to meet their state's needs.

---

[5]Illinois currently allows retail access only for commercial and industrial customers. All customers of investor-owned utilities in Illinois will be able to choose their own electric supplier by May 1, 2002.

The California crisis has only made those states that had declined to move toward electric restructuring in the first place even more reluctant to move from their original positions. This group of states generally believe that they have little to benefit from opening their electric industries to competition anytime soon, since these states enjoy relatively low electric rates compared with the rest of the nation. In total, 14 states have decided that electric restructuring is not in their best interest at this time and are currently no longer actively considering it.[6] This is an interesting turn of events, considering that before the California meltdown, every state in the nation was at least studying the issue–as 12 states continue to do.[7] No state has passed restructuring legislation since California's problems began last summer and no state at this time appears to be close to doing so.

---

[6]The 14 states that are not considering or are no longer considering electric restructuring at this time are Alabama, Alaska, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Mississippi, South Carolina, South Dakota, Utah, Wisconsin, and Wyoming.

[7]The 12 states that are continuing to study restructuring (at least in a minimal way) are: Florida, Georgia, Kentucky, Louisiana, Minnesota, Missouri, Nebraska, North Carolina, North Dakota, Tennessee, Vermont, and Washington. Many of these states, it should be noted, are only considering the issue in some limited form, and are unlikely to pass any legislation soon.

Figure 1. Status of State Electric Industry Restructuring.

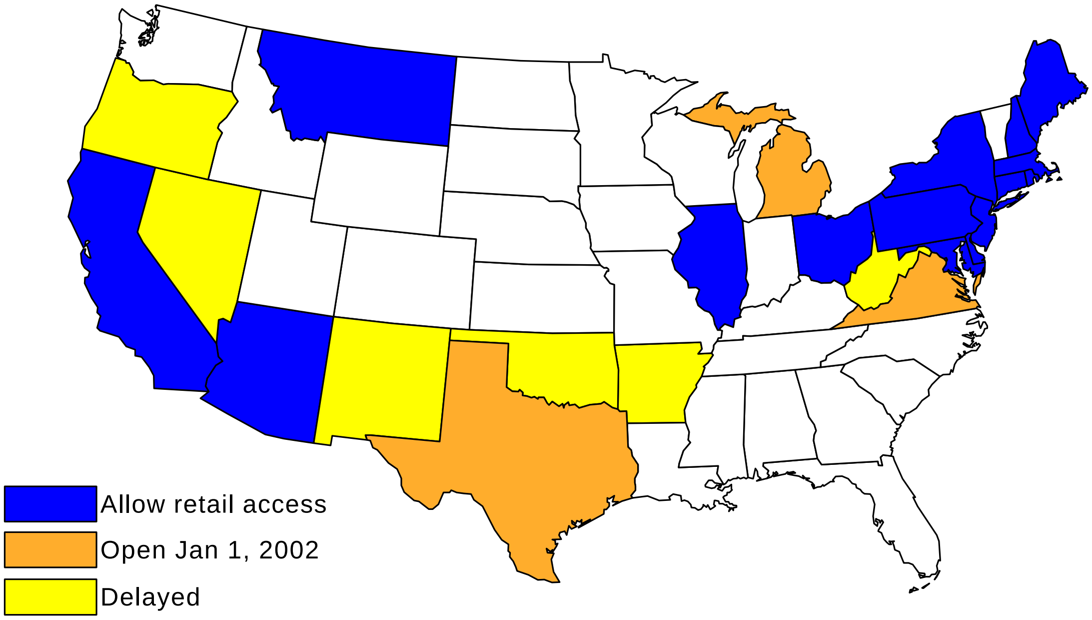


Table 1. Summary of State Electric Restructuring Activities.

States that currently allow retail access (15 states plus Washington, D.C.):
Arizona, California, Connecticut, Delaware, District of Columbia, Illinois (large customers), Maine, Maryland, Massachusetts, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, and Rhode Island.

States that plan to allow retail access beginning January 2002 (3 states):
Michigan, Texas, and Virginia.

States that have postponed or delayed indefinitely retail access (6 states):
Arkansas (delayed until October 2003), Nevada (delayed indefinitely), New Mexico (delayed until 2007), Oklahoma (2003 or later), Oregon (for large customers; delayed until March 2002) and West Virginia (indefinite).

The remaining states: 12 continue to study the issue and 14 have either decided that restructuring is not in their interest at this time or have dropped it from further consideration at this time.

Source: NRRI electric restructuring survey.

Electric restructuring activity in the mid-Atlantic Region

Virginia will phase-in retail access beginning January 2002. Most customers will be phased-in by January 2003 and all customers will have retail access by January 2004.

Retail choice started in Delaware on October 1, 1999, but very few customers have switched. Only seven non-residential customers in Conectiv's territory have switched. There was an offer made by Allegheny Energy to Conectiv residential customers for the contract period of between January and May 2001. But after the contracts ended, they were not renewed. Less than 100 residential customers have switched in total. When their contracts were dropped, they returned to the default supplier, Conectiv. Conectiv has a total of 265, 877 customers, comprising 237,671 residential and 28,206 non-residential customers. Currently, there are no suppliers offering choice to residential customers, and there are no residential customers taking service from an alternate supplier. Delaware Electric Cooperative has no suppliers offering alternate supply service in their service area. They have a total of 58,829 customers: 53,733 are residential, and 5,096 are non-residential. No Delaware Electric Cooperative customer has switched suppliers.

In the District of Columbia, the total number of residential customers who have switched is 1,056 or 0.5 percent. The total number of commercial customers who have switched is 2,307, which is 8.5 percent of the total.

Maryland customers in BG&E and PEPCO territories only had offers from green suppliers in the 6.5 to 7.0 cents/kWh range (compared to BG&E's standard offer service at 4.3 cents, and PEPCO's at 5 cents). There was not much customer interest.

Electric restructuring has been put on the back burner for the time being in North Carolina. A legislative study commission considering the feasibility of electric restructuring decided against recommending new laws for electric restructuring before the start of the 2001 legislative session. In May 2000, the legislative study commission submitted a recommendation that consumers be allowed to choose their electricity providers by 2006, and for rates to be capped until December 31, 2004. That plan still stands.

In South Carolina, the 2001 legislative session ended with no action taken on any restructuring legislation. There was a bill that indicated that the legislature would continue to study the issue.

As noted, West Virginia has delayed proceeding with its restructuring plan. The legislature approved the West Virginia PSC's restructuring plan in March 2000. But between then and the beginning of the following legislative session in February 2001, California’s problems occurred. As such, legislators did not consider any legislation making the necessary tax changes in the 2001 legislative session so that the WV PSC's restructuring plan could be implemented. It is also unlikely that any legislation would be considered in the 2002 legislative session.

Review of Four States: California, Massachusetts, New Jersey, and Pennsylvania

One question that has been raised repeatedly since the summer of 2000 is whether other states will follow in California's footsteps. Among the states with open markets, three have been the most active in terms of competitive suppliers and customer participation–New Jersey, Pennsylvania, and, until recently, California. These three states plus Massachusetts, a state that began retail access relatively early, are examined in terms of recent performance, in terms of where they are similar and different, and to try to determine any discernible trends and patterns.

California

In California, the bundled prices to compare[8] increased steadily over the nine months from July 2000 to March 2001. Strikingly, the market was dominated by offers from suppliers selling power from renewable resources (see Table 2). Both the number of competitive offers and the number of suppliers steadily decreased during the last year. Currently, there is only one renewable offer in both Southern California Edison and Pacific Gas and Electric territories. There have been no offers of any kind in the San Diego Gas and Electric area this year. Figure 2 below summarizes the California statewide total offers and number of offers below the price to compare for July 2000 and July 2001.

Because the utilities' bundled prices to compare increased over the months from July 2000 until March 2001, the savings from switching to a competitor were enhanced. The percent savings on the best offer were consistently above 10 percent and hit a high of 15.7 percent in September 2000 in Southern California Edison's territory. May and July savings, however, dropped to 2.5 and 2.7 percent. Moreover, as wholesale prices started increasing dramatically during 2000, the number of long-term contracts dropped

---

[8]As explained earlier, the term price to compare refers to the price for generation service that the customer can use to compare competitive offers. This is also referred to as standard offer, shopping credit, or backout rate (terminology differs from state to state). *Bundled* price to compare is used here to refer to the total price per kWh for delivered power paid by the customer, including generation, transmission, distribution, other customer charges, and less any discounts that may apply.

to zero by March of 2001 for both companies, and the one remaining offer this year is a monthly contract, where the price for power is adjusted each month to reflect market prices. This appears to be a common strategy used by the alternative suppliers to adjust for wholesale price increases and volatility.

Table 2. Summary of California's Residential Retail Electric Market.

Southern California Edison	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
Number of renewable offers	13	13	15	7	1	1	1
Number of offers from various sources	1	1	1	0	0	0	0
Total number of offers	14	14	16	7	1	1	1
Number of monthly contracts	11	11	13	6	1	1	1
Number of long-term or year-long contracts	3	3	3	1	0	0	0
Number of offers below price-to-compare	7	5	8	1	1	1	1
Number of suppliers	11	11	13	5	1	1	1
Bundled "Price to Compare" (cents/kWh)*	12.75	12.75	13.13	14.13	14.13	14.13	14.13
Percent Savings on Lowest Offer	11.5%	15.7%	13.0%	10.6%	10.6%	2.5%	2.5%
Pacific Gas & Electric							
Number of renewable offers	13	14	15	7	1	1	1
Number of offers from various sources	1	1	0	0	0	0	0
Total number of offers	14	15	15	7	1	1	1
Number of monthly contracts	11	11	12	6	1	1	1
Number of long-term or year-long contracts	3	3	3	1	0	0	0
Number of offers below price-to-compare	6	5	6	1	1	1	1
Number of suppliers	11	12	12	5	1	1	1
Bundled "Price to Compare" (cents/kWh)*	12.28	12.28	12.31	13.31	13.31	12.97	12.97
Percent Savings on Lowest Offer	12.0%	10.2%	13.9%	11.3%	11.3%	2.7%	2.7%

*Bundled price to compare is the total price for delivered power paid by the customer, including generation, transmission, distribution, other customer charges, and less any discounts that may apply. Data Source: Compiled from data obtained from *Wattage Monitor* (http://www.wattagemonitor.com), other industry sources used in compilation.

As would be expected given wholesale market prices, retail customer participation rates in California have dropped considerably, as shown in Table 3. From late May of 2000–about the beginning of California's troubles–to late April of this year, the percentage of residential customers that were "direct access" (that is, selected an alternative electric supplier) was cut in half, from 1.8 percent to 0.9 percent. For large industrial customers (greater than 500 kW) the drop was even more dramatic, decreasing from almost 20 percent of these customers to just 2.55 percent. This represents a drop from 36 percent to only 3 percent of the large industrial customer load

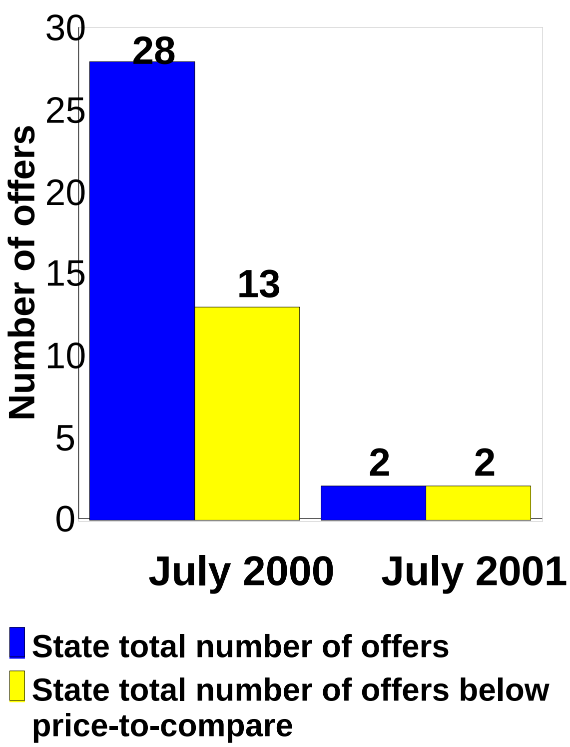
Table 3. "Direct Access" Customers in California.

Customer Class	June 15, 2000	May 15, 2001
Residential	1.8%	0.86%
Commercial <20 kW	4.1%	0.77%
Commercial 20 - 500 kW	7.3%	1.04%
Industrial > 500 kW	19.7%	2.55%
Agricultural	4.2%	0.32%
Total	2.2%	0.85%

Source: California Public Utilities Commission.

.

Fig. 2. California statewide residential offers



(as measured in kWhs). In May 2000, 16 percent of the total load had selected a supplier for direct access; by late April of this year, it was just over 2 percent. As long-term customer commitments expire, the percentages will likely continue to decline as long as wholesale prices continue to remain relatively high.

Because of the retail price caps and skyrocketing wholesale prices, the utility distribution companies (UDCs) were unable to pass the higher wholesale costs through to retail customers and, consequently, accumulated approximately $14 billion in uncollected expenses. The ensuing financial difficulties of the UDCs (and eventual filing for bankruptcy protection by PG&E) made suppliers unwilling to sell to them.

Therefore, since January of this year, the state of California has been purchasing wholesale power for the UDC customers through its Department of Water Resources (DWR). California wholesale prices and the power prices paid by the DWR are shown in the next section. Because the DWR contracts are long term (up to ten years) and were agreed to when prices were at record highs, the state is currently considering suspending retail access to ensure recovery of the contracted power costs.

Massachusetts

Retail activity in Massachusetts could best be described as "quiet" (Table 4). In July 2001, there was no activity in the state's residential market–there were no offers at all in any of the service territories. Figure 3 below summarizes the Massachusetts statewide total offers and number of offers below the price to compare for July 2000 and July 2001.

For most of the last year, customers in Massachusetts saw at most one alternative offer in their service territory, except Cambridge Electric and Boston Edison that each had as many as three during 2000. Percent savings on the lowest offers were between 1.6 to 5.0 percent for most territories, with Boston Edison and Cambridge Electric Company again being exceptions, their customers had offers of 5 to 7.7 percent.

Between November 2000 and May 2001, percent savings on the lowest residential offer in all service territories (except for November 2000 for Boston Edison) held steady at about 5.0 percent–a result of offers by ServiSense, a utility bill bundling service.

Also, not surprisingly, customer switching activity is also relatively quiet, as Figure 4 shows. The most active customer group, large commercial and industrial customers, peaked at just under 12 percent in late 1999 and has steadily declined to about six and one-half percent last spring. All other customer groups are currently below one percent of customers choosing an alternative supplier.

Table 4. Summary of Massachusetts' Residential Retail Electric Market.

	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
Commonwealth Electric Co.							
Number of renewable offers	0	0	0	0	1	1	0
Number of offers from various sources	1	1	1	1	1	1	0
Total number of offers	1	1	1	1	2	2	0
Number of monthly contracts	1	1	1	1	2	2	0
Number of long-term or year-long contracts	0	0	0	0	0	0	0
Number of offers below price-to-compare	1	1	1	1	1	1	0
Number of suppliers	1	1	1	1	2	2	0
Bundled "Price to Compare" (cents/kWh)*	12.07	12.07	12.07	12.07	13.78	13.79	0
Percent Savings on Lowest Offer	1.6%	1.6%	5.0%	5.0%	4.8%	5.0%	-
Cambridge Electric Co.							
Number of renewable offers	0	0	0	0	1	1	0
Number of offers from various sources	3	3	1	1	1	1	0
Total number of offers	3	3	1	1	2	2	0
Number of monthly contracts	2	3	1	1	2	2	0
Number of long-term or year-long contracts	1	0	0	0	0	0	0
Number of offers below price-to-compare	3	3	1	1	1	1	0
Number of suppliers	3	3	1	1	2	2	0
Bundled "Price to Compare" (cents/kWh)*	9.87	9.87	9.87	9.87	12.96	12.96	0
Percent Savings on Lowest Offer	7.7%	7.7%	5.0%	5.0%	5.0%	5.0%	-
Western Mass Electric Co.							
Number of renewable offers	0	0	0	0	1	1	0
Number of offers from various sources	1	1	1	1	1	1	0
Total number of offers	1	1	1	1	2	2	0
Number of monthly contracts	1	1	1	1	2	2	0
Number of long-term or year-long contracts	0	0	0	0	0	0	0
Number of offers below price-to-compare	1	1	1	1	1	1	0
Number of suppliers	1	1	1	1	2	2	0
Bundled "Price to Compare" (cents/kWh)*	11.05	11.05	11.05	11.05	12.78	12.78	0
Percent Savings on Lowest Offer	2.0%	2.0%	5.0%	5.0%	5.0%	5.0%	-
Boston Edison Co.							
Number of renewable offers	0	0	0	0	1	1	0
Number of offers from various sources	3	3	3	1	1	1	0
Total number of offers	3	3	3	1	2	2	0
Number of monthly contracts	2	3	3	1	2	2	0
Number of long-term or year-long contracts	1	0	0	0	0	0	0
Number of offers below price-to-compare	3	3	3	1	1	1	0
Number of suppliers	3	3	3	1	2	2	0
Bundled "Price to Compare" (cents/kWh)*	12.32	12.32	12.32	12.32	14.02	14.02	0
Percent Savings on Lowest Offer	7.3%	7.3%	7.3%	5.0%	5.0%	5.0%	-
Fitchburg Gas & Electric Light Co.							
Number of renewable offers	0	0	0	0	1	1	0
Number of offers from various sources	1	1	1	1	1	1	0
Total number of offers	1	1	1	1	2	2	0
Number of monthly contracts	1	1	1	1	2	2	0

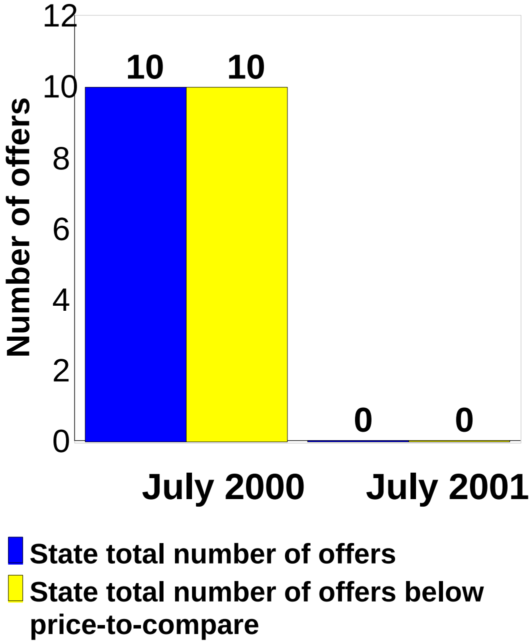
	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
Number of long-term or year-long contracts	0	0	0	0	0	0	0
Number of offers below price-to-compare	1	1	1	1	1	1	0
Number of suppliers	1	1	1	1	2	2	0
Bundled "Price to Compare" (cents/kWh)*	11.55	11.55	11.55	11.55	13.21	13.21	0
Percent Savings on Lowest Offer	1.7%	1.7%	5.0%	5.0%	5.0%	5.0%	-
Massachusetts Electric Co.							
Number of renewable offers	0	0	0	0	1	1	0
Number of offers from various sources	1	1	1	1	1	1	0
Total number of offers	1	1	1	1	2	2	0
Number of monthly contracts	1	1	1	1	2	2	0
Number of long-term or year-long contracts	0	0	0	0	0	0	0
Number of offers below price-to-compare	1	1	1	1	1	1	0
Number of suppliers	1	1	1	1	2	2	0
Bundled "Price to Compare" (cents/kWh)*	9.38	9.38	9.38	9.38	11.16	11.16	0
Percent Savings on Lowest Offer	2.0%	2.0%	5.0%	5.0%	5.0%	5.0%	-

*Bundled price to compare is the total price for delivered power paid by the customer, including generation, transmission, distribution, other customer charges, and less any discounts that may apply.
Data Source: Compiled from data obtained from *Wattage Monitor* (http://www.wattagemonitor.com).

The vast majority of customers in Massachusetts have not chosen a competitive supplier for generation service and are provided generation by the distribution companies as either standard offer service or default service. Customers that did not select a competitive supplier beginning on March 1,1998 were placed on standard offer service. The standard offer service will be available through February 2005. Customers who moved into a distribution company's service territory after March 1, 1998, however, will receive default service unless they select a competitive supplier. In general, once customers select a competitive supplier, they are no longer eligible to return to standard offer service, except for (1) low-income customers, who can return at any time, and (2) customers participating in a municipal aggregation program who can return within 180 days of joining the program.

The rates for standard offer service are regulated by the Massachusetts Department of Telecommunications and Energy (the Department) and are set at levels that provide a 15 percent overall bill reduction (adjusted for inflation) to customers receiving standard offer service, when compared to the customers' bills from 1997. Distribution companies procure supply for default service through competitive solicitations. Prices for default service are also regulated by the Department and may

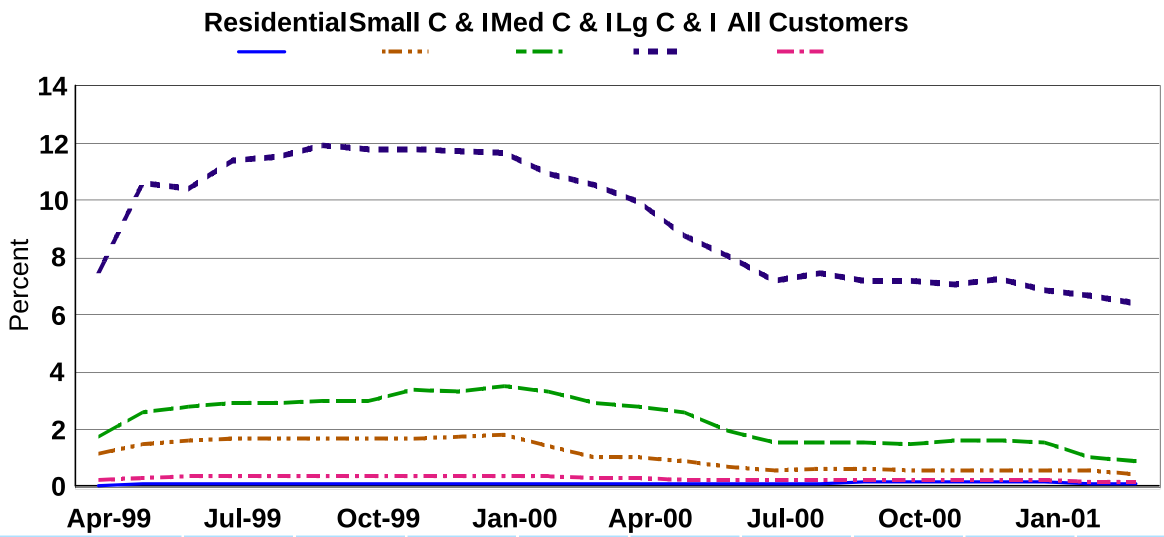
Fig. 3. Massachusetts statewide residential offers



not exceed the average market price for electricity in New England. Default service customers have two pricing options: (1) a variable pricing option in which the price changes monthly; and (2) a fixed pricing option in which the variable monthly prices are averaged and remain constant for either six or twelve month periods.

Both standard offer and default prices have risen dramatically since competition began in 1998 in Massachusetts. For example, the 1998 standard offer price was 3.2 cents/kWh for Boston Edison customers. Currently, Boston Edison's residential standard offer rate for January through June 2001 was 6.215 cents/kWh and increased to 7.445 cents/kWh for July through December. Monthly default service for July and August was just over 11 cents/kWh and decreases to a range of between 7.4 to 7.66 cents/kWh for September through December of 2001. Fixed default service for January through June was 7.032 cents/kWh and increased to 8.743 cents/kWh for July through December.

Figure 4. Massachusetts customer switching trends.



	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Mar-01
Residential (Non Low Income)	0.06	0.09	0.09	0.09	0.10	0.12	0.13	0.14	0.08
Small C & I	1.16	1.66	1.68	1.78	1.01	0.59	0.58	0.57	0.46
Medium C & I	1.71	2.93	2.99	3.53	2.82	1.55	1.46	1.57	0.86
Large C & I	7.48	11.40	11.78	11.68	9.94	7.22	7.21	6.88	6.44
All Customer Groups	0.23	0.34	0.35	0.37	0.28	0.21	0.22	0.23	0.15

Source: Massachusetts Division of Energy Resources, June 2001.

New Jersey

Between July 2000 and January 2001, bundled prices to compare in New Jersey declined (See Table 5). All three New Jersey distribution companies saw declines in November 2000—PSG&E by 14.8 percent, GPU by 11.5 percent, and Conectiv by 4.3 percent. Figure 5 below summarizes the New Jersey statewide total offers and number of offers below the price to compare for July 2000 and July 2001.

Commission officials say seasonal factors might have triggered the fall in prices, since less electricity is used during the winter months. They suggest that the type and number of customers within each individual utility's service territory might explain why Conectiv was not able to offer as large a rate cut as PSE&G or GPU. They note that Conectiv has casinos in its service areas, which are in operation all year and use as much electricity as it takes to service a small town. As a result, Conectiv does not see as large a drop in electric use during winter months as the other companies. Moreover, Conectiv's territory covers a large land area, with a little over 300,000 to 350,000 customers, while PSE&G caters to a densely populated territory of nearly two million customers.

The prices to compare held steady until March 2001, in which another round of price changes kicked in. The bundled prices to compare for PSG&E dropped by 3.3 percent, and that for GPU dropped by 1.1 percent. Conectiv's customers, however, saw a jump in prices by 4.2 percent, and another jump of 2.6 percent in July 2001. The rise in Conectiv's prices was in line with expectations, since electric use usually increase in summer months. But the drop in PSG&E's and GPU's rates was a surprising trend. Observers attribute this anomaly to the fact that the New Jersey Board of Utilities had mandated that rates be reduced by 5 percent each year for local distribution companies, starting from 1999 through 2002, with the goal of a 15 percent reduction across-the-board at the end of the three years.

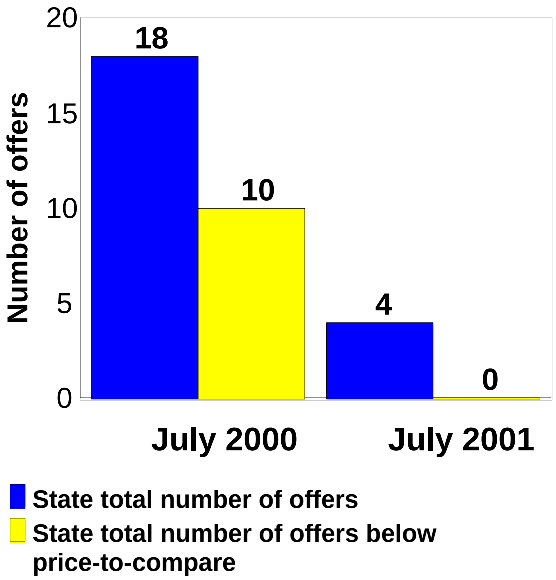
This steady decline in the bundled prices to compare for PSE&G and GPU resulted in a drop in the number of offers below the price to compare and put a dent in potential savings from switching to an alternative supplier. The *average* percent savings from switching to suppliers offering prices below the bundled price to compare ranged about 4 to 6 percent.

Table 5. Summary of New Jersey's Residential Retail Electric Market.

Public Service Electric and Gas Company	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
Number of renewable offers	2	2	2	2	3	3	1
Number of offers from various sources	3	5	7	5	5	2	1
Total number of offers	5	7	9	7	8	5	2
Number of monthly contracts	2	2	3	3	4	4	1
Number of long-term or year-long contracts	3	5	6	4	4	1	1
Number of offers below price-to-compare	2	4	6	6	5	1	0
Number of suppliers	3	4	6	5	6	4	2
Bundled "Price to Compare" (cents/kWh)*	13.77	13.77	11.73	11.73	11.34	11.34	11.34
Percent Savings on Lowest Offer	4.4%	6.8%	5.4%	9.0%	6.0%	4.8%	NA-
GPU/Jersey Central Power and Light Co.							
Number of renewable offers	2	2	2	2	3	3	1
Number of offers from various sources	3	3	4	2	2	1	0
Total number of offers	5	5	6	4	5	4	1
Number of monthly contracts	2	2	3	3	4	4	1
Number of long-term or year-long contracts	3	3	3	1	1	0	0
Number of offers below price-to-compare	4	4	3	2	2	1	0
Number of suppliers	3	3	4	3	4	3	1
Bundled "Price to Compare" (cents/kWh)*	12.70	12.70	11.24	11.24	11.12	11.12	11.12
Percent Savings on Lowest Offer	13.2%	13.2%	5.0%	5.0%	5.0%	5.0%	NA
Conectiv							
Number of renewable offers	4	6	5	2	3	3	1
Number of offers from various sources	4	5	4	3	3	1	0
Total number of offers	8	11	9	5	6	4	1
Number of monthly contracts	2	2	3	3	4	4	1
Number of long-term or year-long contracts	6	9	6	2	2	0	0
Number of offers below price-to-compare	4	5	4	4	5	3	0
Number of suppliers	4	5	6	4	5	3	1
Bundled "Price to Compare" (cents/kWh)*	11.97	11.97	11.45	11.45	11.93	11.93	12.25
Percent Savings on Lowest Offer	6.7%	6.7%	7.0%	7.0%	17.7%	11.4%	NA

*Bundled price to compare is the total price for delivered power paid by the customer, including generation, transmission, distribution, other customer charges, and less any discounts that may apply.
Note: Conectiv Energy, supplying both renewable and various, was counted as two suppliers for July 2000 and September 2000 and counted Conectiv Energy (renewable) as a supplier for November 2000.
Data Source: Compiled from data obtained from Wattage Monitor (http://www.wattagemonitor.com).

Fig. 5. New Jersey statewide residential offers



The exception was Conectiv; where the rise in Conectiv's price to compare resulted in shaper increases in the average percent savings for Conectiv customers who had switched to alternative suppliers. Average percent savings for these customers jumped by 10.7 percent in March 2001, from 4.2 percent in January 2001, while those who switched to the supplier with the lowest offer enjoyed a huge increase in savings of 17.7 percent in March 2001, up from 7 percent in January 2001.

No New Jersey company had offers below the price to compare in July 2001.

As would be expected from the reduced savings opportunities, customer participation rates have plummeted in New Jersey since the fall of 2000 (Table 6). Customer participation rates in all the service territories dropped considerably. Even Conectiv saw a drop in the customer participation rate—from nearly 6 percent of its customers switching to an alternative supplier last November, to 1.5 percent in May. For non-residential customers, that figure has dropped from nearly 12 percent to just over one percent. Statewide, for both residential and non-residential customers, the percentages were cut in half from last fall.

Table 6. Percent of New Jersey's Customers Served by an Alternative Supplier.

	Residential		**Nonresidential**	
	Nov 2000	May 2001	Nov 2000	May 2001
Conectiv	5.9	1.5	11.8	1.1
GPU	1.0	0.2	5.8	1.1
PSE&G	1.8	1.5	6.3	5.2
State Total	2.2	1.1	6.9	3.4

Pennsylvania

In many respects, Pennsylvania has been the poster child for how things can go right with electric restructuring. Nevertheless, even here, there are signs of recent weakness.

The bundled prices to compare in Pennsylvania have held relatively steady over the past nine months, although March 2001 saw marginal increases for PECO and Allegheny Energy (Table 7). As such, many suppliers that were offering contracts below the bundled price-to-compare were only able to price their offers at about 5 percent below each utility's price-to-compare.

Pennsylvania has seen a sharp drop in the number of competing offers since a year ago. For July 2001, PECO Energy was the only Pennsylvania distribution company that had any offers below the price to compare. Just last May, there were 26 competing offers in PECO Energy Company's territory alone. A year later, in May 2001, the number of competing offers has dwindled down to 11—a drop of nearly 60 percent. Offers below the price to compare have dropped from 9 in March 2001 to 5 in April 2001 and, subsequently, to 2 in May and July of 2001. Several higher priced renewable options remain.

Another interesting trend developing in Pennsylvania: monthly contracts were already accounting for most of the contracts offered since July 2000, as compared to New Jersey, where monthly contracts came to take on a greater proportion of total offers only in November 2000. Monthly contracts have consistently accounted for more than half of the competitive offers in each territory. In fact, all the alternate suppliers in four of the utilities' territories, namely that of Allegheny Power, GPU/Metropolitan Edison, UGI Utilities and Pennsylvania Electric Company, have been offering monthly contracts since July 2000.

The two GPU Energy companies that operate in Pennsylvania, Metropolitan Edison and Pennsylvania Electric had four and six offers below the price to compare in July of 2000. Since then, these offers have dropped to none. As noted in footnote 4 above, a settlement reached in June of 2001 allows GPU to defer for ratemaking and accounting purposes the difference between what it can charge customers for generation under the rate cap and its actual cost to supply electricity (GPU had sold its capacity). Overall customer rates will not increase, but the "shopping credit" or price to compare will increase. GPU stated that it lost $47 million on electricity supply in Pennsylvania in 2000 and estimated it would lose an additional $250 million in 2001 without rate relief. It remains to be seen if the higher shopping credits are sufficient to result in a return of competitive offers for customers of the two GPU companies.

Figure 6 below summarizes the Pennsylvania statewide total offers and number of offers below the price to compare for July 2000 and July 2001 (down from 28 offers to 2). Figure 7 highlights some of the offer trends (seen in Table 7) of the two more active distribution companies in Pennsylvania, PECO Energy and Duquesne Light.

Table 7. Summary of Pennsylvania's Residential Retail Electric Market.

	Jul-00	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
Pennsylvania Power and Light							
Number of renewable offers	4	4	3	3	4	4	2
Number of offers from various sources	4	4	9	4	4	1	0
Total number of offers	8	8	12	7	8	5	2
Number of monthly contracts	6	6	11	6	7	5	2
Number of long-term or year-long contracts	2	2	1	1	1	0	2
Number of offers below price-to-compare	2	2	4	2	2	1	0
Number of suppliers	6	5	7	5	6	3	2
Bundled "Price to Compare" (cents/kWh)*	8.61	8.61	8.61	8.61	8.66	8.66	8.66
Percent Savings on Lowest Offer	10.6%	10.6%	10.6%	5.0%	5.1%	5.0%	NA

	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
PECO Energy							
Number of renewable offers	5	6	6	6	7	7	5
Number of offers from various sources	11	14	15	9	10	4	2
Total number of offers	16	20	21	15	17	11	7
Number of monthly contracts	9	11	11	7	9	6	4
Number of long-term or year-long contracts	7	9	10	8	8	5	3
Number of offers below price-to-compare	6	13	11	9	9	2	2
Number of suppliers	13	15	17	12	14	8	7
Bundled "Price to Compare" (cents/kWh)*	13.27	13.27	12.86	12.86	13.58	13.58	14.10
Percent Savings on Lowest Offer	9.0%	11.7%	10.8%	10.8%	6.8%	5.0%	2.6%
Allegheny Power							
Number of renewable offers	4	4	3	3	4	4	2
Number of offers from various sources	2	2	1	1	1	1	0
Total number of offers	6	6	4	4	5	5	2
Number of monthly contracts	4	4	4	4	5	5	2
Number of long-term or year-long contracts	2	2	0	0	0	0	0
Number of offers below price-to-compare	2	2	1	1	1	1	0
Number of suppliers	3	3	2	2	3	3	2
Bundled "Price to Compare" (cents/kWh)*	6.76	6.76	6.76	6.76	7.34	7.34	7.34
Percent Savings on Lowest Offer	4.8%	9.6%	5.0%	5.0%	5.0%	5.0%	NA
Duquesne Light							
Number of renewable offers	4	4	3	3	4	4	2
Number of offers from various sources	3	3	5	3	1	2	1
Total number of offers	7	7	8	6	5	6	3
Number of monthly contracts	5	5	7	5	5	5	2
Number of long-term or year-long contracts	2	2	1	1	1	1	0
Number of offers below price-to-compare	3	3	5	3	1	1	0
Number of suppliers	4	4	6	4	4	4	3
Bundled "Price to Compare" (cents/kWh)*	12.52	12.52	12.52	12.52	12.52	12.52	12.52
Percent Savings on Lowest Offer	7.7%	7.7%	7.7%	5.8%	5.0%	5.0%	NA
Pennsylvania Power Company							
Number of renewable offers	4	4	3	3	4	4	2
Number of offers from various sources	5	5	7	3	3	2	1
Total number of offers	9	9	10	6	7	6	3
Number of monthly contracts	7	7	9	5	6	5	2
Number of long-term or year-long contracts	2	2	1	1	1	1	1
Number of offers below price-to-compare	3	3	5	3	3	2	0
Number of suppliers	6	6	8	4	5	4	3
Bundled "Price to Compare" (cents/kWh)*	10.41	10.41	10.41	10.41	10.41	10.41	10.41
Percent Savings on Lowest Offer	7.5%	7.5%	9.6%	5.0%	5.0%	5.0%	NA
Metropolitan Edison Company							
Number of renewable offers	5	5	3	3	4	4	2
Number of offers from various sources	6	6	7	3	3	1	0
Total number of offers	11	11	10	6	7	5	2
Number of monthly contracts	8	8	10	6	7	5	2
Number of long-term or year-long contracts	3	3	0	0	0	0	0

	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
Number of offers below price-to-compare	4	4	5	1	1	1	0
Number of suppliers	8	8	8	4	5	3	2
Bundled "Price to Compare" (cents/kWh)*	9.15	9.15	9.15	9.15	9.19	9.19	9.19
Percent Savings on Lowest Offer	10.0%	10.0%	10.9%	5.0%	5.0%	5.0%	NA
UGI Utilities							
Number of renewable offers	4	4	3	3	4	4	2
Number of offers from various sources	3	3	2	2	2	1	0
Total number of offers	7	7	5	5	6	5	2
Number of monthly contracts	5	5	5	5	6	5	2
Number of long-term or year-long contracts	2	2	0	0	0	0	0
Number of offers below price-to-compare	2	2	1	1	2	1	0
Number of suppliers	4	4	3	3	4	3	2
Bundled "Price to Compare" (cents/kWh)*	9.45	9.45	9.45	9.45	9.49	9.49	9.49
Percent Savings on Lowest Offer	7.4%	7.4%	5.0%	5.0%	5.0%	5.0%	NA
Pennsylvania Electric Company							
Number of renewable offers	4	4	3	3	4	4	2
Number of offers from various sources	7	7	7	3	3	1	0
Total number of offers	11	11	10	6	7	5	2
Number of monthly contracts	8	8	10	6	7	5	2
Number of long-term or year-long contracts	3	3	0	0	0	0	0
Number of offers below price-to-compare	6	6	7	3	4	2	0
Number of suppliers	9	9	8	4	5	3	2
Bundled "Price to Compare" (cents/kWh)*	8.89	8.89	8.89	8.89	8.91	8.91	8.91
Percent Savings on Lowest Offer	10.2%	10.2%	10.2%	5.0%	5.1%	5.1%	NA

*Bundled price to compare is the total price for delivered power paid by the customer, including generation, transmission, distribution, other customer charges, and less any discounts that may apply.

Note: Counted Online.com twice for September 2000 for Pennsylvania Electric Company because it was providing offers from both renewable and various sources.

Data Source: Compiled from data obtained from *Wattage Monitor* (http://www.wattagemonitor.com).

Pennsylvania has consistently had the highest overall customer participation rates of any state. However, as Table 8 shows, nearly all of this activity has been limited to two utility distribution company areas, Duquesne Light and PECO Energy. All other companies' activity has decreased. The highest participation rate among these others was obtained by Penn Power, which is now at only 1.1 percent. All other Pennsylvania distribution companies, besides Duquesne and PECO Energy, are now well less than one percent. Duquesne Light's participation rate has remained about the same since last fall, and, when PECO Energy customers that were assigned to another supplier are subtracted, the percentage there drops to 12.3 percent for July of this year, which is a drop of almost 4 percentage points from where it was earlier this year. Figure 8 summarizes the amount of total load (in MWs) in Pennsylvania that was served by alternative suppliers in July 2000 and July 2001.

Fig. 6. Pennsylvania statewide residential offers

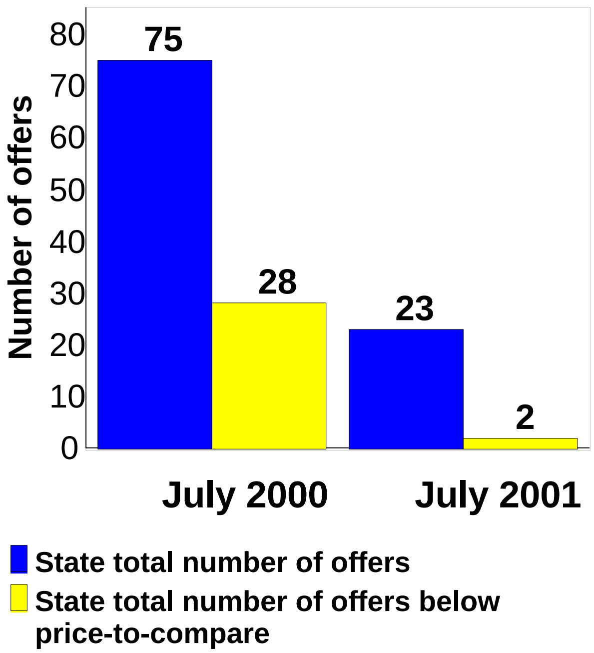
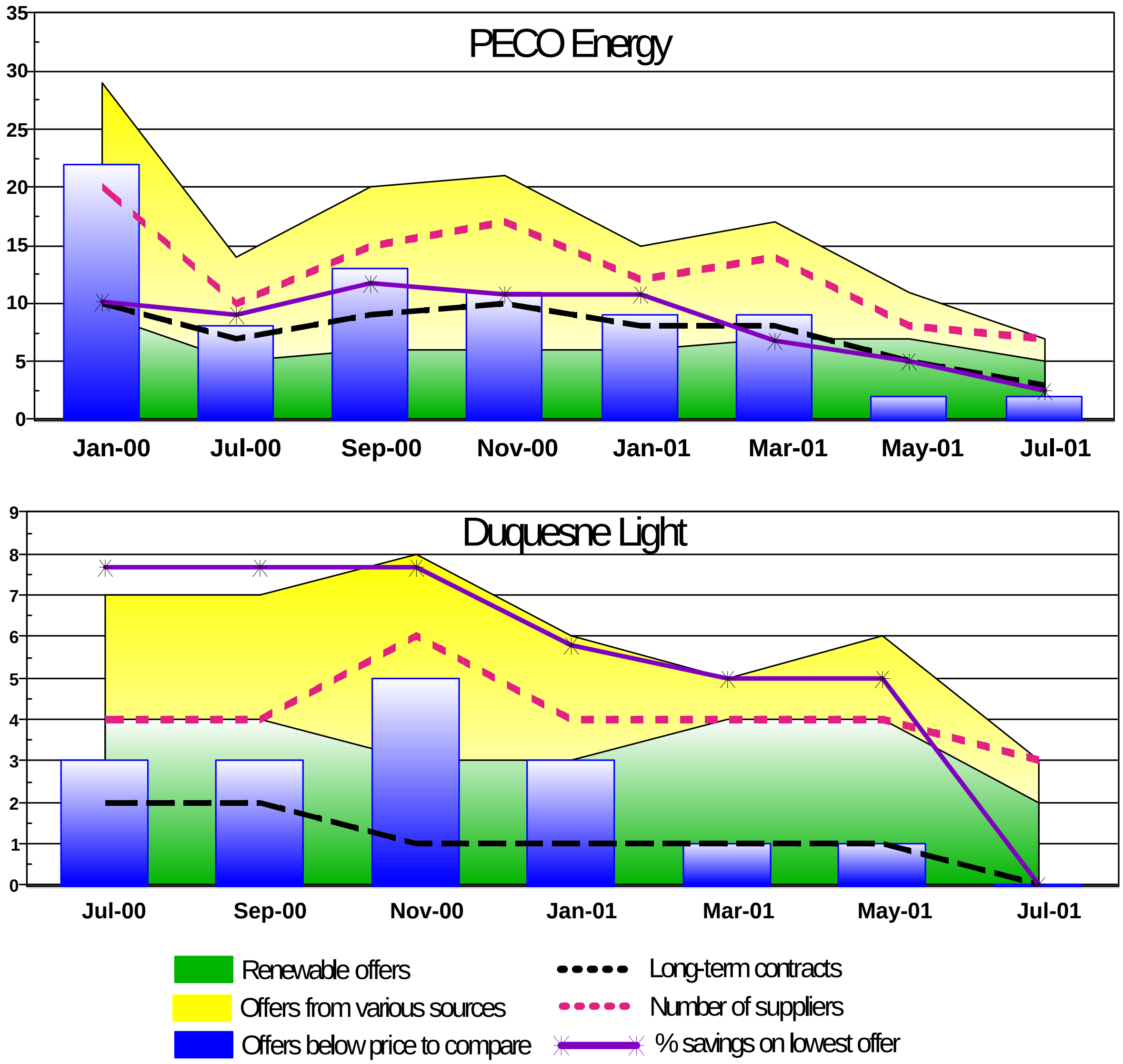


Figure 7. PECO Energy and Duquesne Light offer trends.



Data Source: Compiled from data obtained from Wattage Monitor (http://www.wattagemonitor.com)

Fig. 8. Pennsylvania total load served by alternative suppliers

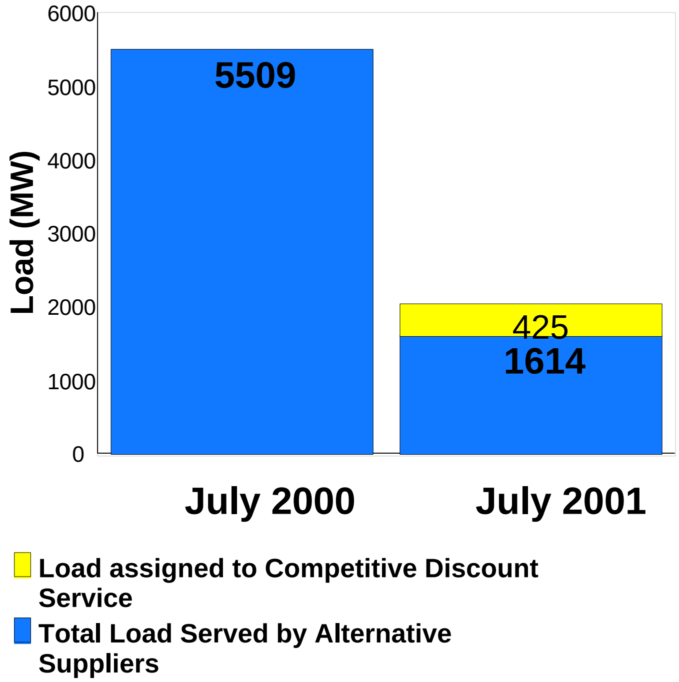


Table 8. Percent of Pennsylvania's Residential Customers Served by an Alternative Supplier.

	4/99	7/99	10/99	1/00	4/00	7/00	10/00	1/01	4/01	7/01
Allegheny	1.4	1.4	1.4	1.3	1.1	0.6	0.5	0.5	0.4	0.3
Duquesne	13.1	14.3	19.1	22.2	25.5	29.4	33.3	33.6	33.4	32.6
GPU Energy	3.8	4.1	4.9	5.1	5	4.1	4.7	4.7	3.9	0.5
PECO Energy	12.8	14.9	14.5	14.9	15.3	15.8	15.2	16.2	34.1*	28.7**
Penn Power	6.2	5.9	6	6	6.3	6.4	6.3	6.2	6.3	1.1
PP&L	2	2.3	2.3	2.3	2.4	2.3	2	2	1.6	0.2
UGI	4.3	4.7	4.3	4.2	3.9	3.4	3.3	3.3	3.1	0.2

* Includes 18.5% residential customers assigned to Competitive Discount Service.

**includes 16.4% residential customers assigned to Competitive Discount Service.

Data Source: Pennsylvania Office of Consumer Advocate, "Pennsylvania Electric Shopping Statistics," April 1999 through April 2001.

Other State Activities

Ohio

Retail competition began in Ohio on January first of this year. Early returns from Ohio[9] show that nearly all the activity to date has been in the three First Energy companies in northern Ohio. Cleveland Electric Illuminating Company currently has the highest percentage of its customers choosing an alternative supplier at 8.85 percent (9.43 percent of residential customers). This is followed by nearly 6 percent for Ohio Edison Company (6.28 percent residential) and 0.83 percent for Toledo Edison Company (0.62 percent residential). There are unique circumstances attending the provision of generation service to these customers, as will be explained in more detail below.

All the remaining distribution companies in Ohio have less than one-tenth of one percent of all customers choosing an alternative supplier. The highest commercial customer percentage is in Cleveland Electric Illuminating's service area at 5.4 percent. For industrial customers, 38 percent of Toledo Edison, 34.8 percent of Ohio Edison, and 12.89 percent of Cleveland Electric Illuminating industrial customers have already selected an alternative. The highest switching percent of any customer class for a distribution company not affiliated with First Energy was 1.8 percent of industrial customers in Cincinnati Gas and Electric Company's service area.

Under the Ohio electric restructuring law, municipal governments can aggregate or form a buying pool to purchase electricity on behalf of community residents. A community has to approve a ballot issue authorizing its local government to form such a buying pool. Under provisions in the Ohio law, customers are automatically enrolled with the community's chosen supplier unless a customer returns an "opt-out" card mailed to all eligible customers. The Northeast Ohio Public Energy Council (NOPEC) formed a public electricity buying group to represent more than 450,000 residential

---

[9]Customer percentages reported here are from the Ohio Public Utilities Commission, Division of Market Monitoring & Assessment, March 31, 2001 report.

customers in eight Ohio counties and 95 cities, towns and villages in northeastern Ohio. The elected officials of these governments combined their communities together to form the NOPEC buying pool. NOPEC signed a six-year contract with the Green Mountain Energy that is to provide discounted electricity using electricity generated from natural gas and renewable sources.[10] Green Mountain Energy Company will begin serving residential customers formerly served by Ohio Edison and Cleveland Electric Illuminating beginning in September and November respectively. NOPEC consumers hope to receive a savings on the generation portion of their electric bill from one to three percent below the standard offer price of First Energy, rising to 1.5 to 3.5 percent savings in the final two years of the contract, which runs to December 2006. The size of the actual savings will depend on NOPEC's ability to obtain low-cost energy in the wholesale market.

Under an agreement with the PUCO and various parties, First Energy agreed to make available 1,120 MW of "Market Support Generation" (MSG) to non-affiliated marketers, brokers and aggregators for sales to retail customers during the "market development period," which runs for five year beginning January 1, 2001. This capacity was made available on a first-come-first-served basis to competitive suppliers for committed capacity sales to First Energy's customers. Of the total MSG capacity, 500 MW is reserved for residential customers. Total power allocations for the three northern Ohio First Energy companies are 560 MW from Ohio Edison, 400 MW from Cleveland Electric Illuminating, and 160 MW from Toledo Edison. Prices for the capacity is based on customer class and increases each year that the capacity is made available. Industrial and commercial customer prices are the same for all three First Energy companies, beginning at $26.23/MWh and $30.83/MWh respectively in 2001 and rising to $31.88/MWh and $37.19/MWh respectively in 2005. Residential customer prices for the MSG capacity is $30.03/MWh for Toledo Edison, $31.19/MWh for Ohio Edison, and $31.64/MWh for Cleveland Electric Illuminating. These prices rise to $36.28/MWh,

---

[10]Green Mountain Energy Company stated that its initial target is a wind facility in the 10-megawatt range and supporting the development of at least 100 kW of new solar capacity in the state.

$37.69/MWh, and $38.24/MWh respectively in 2005. It is believed that these prices are initially below market prices for each customer class.

The percentages of customers choosing a supplier that was reported above include MSG resales. The portion of switching that is due to MSG resale is not being reported at this time.

Two Northeastern Retail Markets

On May 1, 2001, New Hampshire joined the ranks of states that allow retail access, although alternative suppliers have not entered the market.

New York has seen moderate competition in its retail market, with most competitive offers in the industrial and commercial sectors. Overall, 4 percent of customers have migrated. The percentage figure is much higher when measured on a load basis–between 15 to 20 percent of the load has migrated. In the residential market, and among the IOUs, Orange & Rockland and Consolidated Edison service territories are among the more active ones. Only one dominant electric service provider has competed in Rochester Gas & Electric’s territory. Niagara Mohawk's territory has been rather quiet, with occasional spurts of activity because of rebate-type programs.

Western Retail Markets

Overall, the combination of relatively high wholesale prices and capped retail prices has eliminated retail access markets throughout the West.

Arizona had an initial round of offers by alternative suppliers in the first two weeks of January, but there are no offers to retail customers currently. Arizona’s experience reflects the situation faced by Montana, where the six licensed power marketers have been largely unsuccessful at enticing residential customers and have withdrawn from making any offers to retail customers.

When power prices in the West soared, most of Montana Power's approximately 285,000 electric customers remained protected from price increases. This is because of a rate cap for residential and small commercial customers and because Montana

Power has been purchasing its electricity at a price locked in by a contract with PPL Montana–the company that purchased Montana Power's generation assets. However, that contract expires in July 2002, the same month the rate cap expires.

Commission officials in Montana say the high wholesale prices in Northwest markets have made consumers wary of leaving the regulated service. The high wholesale prices have also made it difficult for marketers to offer products that are competitive with the incumbent utility's service. Because residential and small commercial customers that remain with the incumbent utility enjoy the stability offered by the rate cap until July 1, 2002, the total number of residential and commercial customers that switched to competitive electricity suppliers has not exceeded 1 percent. The maximum percentage of customers who switched was about 0.3 percent. According to a report by the Montana Public Service Commission on activity between July 1, 1998, and June 30, 2000, 946 residential customers have switched suppliers–and almost all to the same marketer. The marketer was unable to keep its retail prices below the utility rate when the western wholesale markets started to show signs of dysfunction and all the residential customers it acquired were returned to utility service.

During the 2001 session, the Montana legislature drafted 78 bills related to energy and electric industry restructuring. This was in response to the crisis in western wholesale markets and its impact on Montana's retail market. The legislature passed a bill that extended the transition period to 2007. However, the rate cap for residential and small commercial customers will still continue only until July 1, 2002. Initially, when an industrial customer left their utility, they were not able to return to a standard offer. The industrial customer could come back to the utility service, but the utility had no obligation to serve them under traditional tariffs and the utility could charge market prices. The 2001 legislation directs the Montana commission to allow rules to let customers come back to a default supply service. Industrial customers will then be able to come back to a regulated tariff rate during the extended transition period. However, this rate will depend on prices Montana Power receives to purchase wholesale power. Presumably, this will apply to residential and small commercial customers as well after their rate caps expire. Also, there may be conditions put in place such as the customer might have to agree to stay for specified period of time or an exit fee may be required to pay the cost that Montana Power incurred when acting as default supplier.

Initially, after the start of competition for large customers in 1998, industrial customers in Montana were able to find prices that offered a savings on their power purchases. During the last year, however, industrial customers who were in the market for electricity were routinely quoted prices in the $100/MWh to 200/MWh range for year-long contracts. Based upon enrollment activity through June 30, 2000, 1,761 individual accounts of 1,191 customers (some customers have multiple accounts) are buying electric supply from the competitive market. The total load in choice is approximately 259 MW or about 27 percent of pre-choice electric load. Of this, around 230 MW are from the large customer loads. The balance is from naturally pooled individual commercial customer accounts, and a small proportion is associated with the 946 retail accounts. Some industrial customers that are paying market-based prices have shut down and laid off their employees.

In Oregon, the legislature recently voted to delay retail access for its non-residential customers until March 1, 2002. Direct access was to be only offered to nonresidential customers, and was supposed to have started in October 1, 2001. Residential customers in Oregon are not offered direct access. Instead, they are offered a portfolio option administered by the electric utility.

Conclusion

While no state has had the magnitude of problems that California has had—the move to competition in retail electric markets has been slowed considerably. Six states that passed electric restructuring legislation have decided to postpone the move to allow retail access, and at least 14 states that have not passed restructuring legislation have decided that it is not in their interest to continue active consideration of restructuring at this time. No state has passed restructuring legislation since the California meltdown began last summer and no state appears to be ready to do so soon.

Higher and more volatile wholesale market prices across the country have taken their toll on state retail markets. No western state has an active retail market and in the east, states that appeared to be avoiding problems have shown signs of stress. Pennsylvania, which is often regarded as the most successful restructuring state, has seen its number of competitive offers and percent of shopping customers plummet to new lows. New Jersey, which used a similar approach to restructuring as Pennsylvania, has seen its retail markets also contract. These problems can be clearly traced back to higher wholesale market prices, which will be discussed in the next part of this report.

PART II: Status of Electric Wholesale Markets

This section reviews the price trends in the more established wholesale markets of California, New England, PJM, and New York. While still evolving, these regions have been operating spot energy markets and often ancillary services and capacity markets, for more than one year. As a result, they have basic data available on price trends and variations that can be summarized and analyzed. In addition, for each of the markets discussed, this section will summarize available analyses that may shed some light as to how well these markets are performing.

In general, the problems experienced in the wholesale markets across the country, not just in California, explain why retail markets have either had trouble developing or have declined after early encouraging signs of development. As noted in Part I, as wholesale prices for energy and capacity have increased, the headroom available for alternative suppliers to be competitive has been squeezed or has disappeared completely. The headroom between the retail price of generation and the cost of securing power in the wholesale market usually does not increase immediately when wholesale prices rise, since most retail markets have an overall price constraint. Understanding what is occurring in the wholesale market and why prices are increasing, therefore, sheds light on why retail markets are struggling.

How is wholesale market performance measured?

The principal reason, among others,[1] for the movement away from regulation and toward generation competition was the belief that competition would provide better incentives to control costs and that these cost savings would be passed on to consumers–resulting in lower prices for all customer classes. Competition, it is hoped, would provide suppliers with stronger cost discipline incentives to remain competitive than

---

[1]Other reasons include increased use of innovative technologies in generation and more customer options in terms of price, fuel source, and service.

regulation did and drive prices to competitively determined levels as suppliers jockey with each other for customers. It is appropriate, therefore, to judge the performance of the wholesale market based on the extent to which the goal of developing a competitive market is being met.

Ideally, as in the economic textbook case of a perfectly competitive market, there would be many suppliers vying for business. Potential new entrants would encounter few or no entry barriers and this fact would provide an additional incentive to existing suppliers to control costs and offer competitive prices to retain customers. No single supplier or group of suppliers could exercise any control of the price or manipulate it in any significant way. In other words, in a *perfectly* competitive market, suppliers are "price takers" and base their choice of the quantity to supply to the market on this market-determined price.

In reality, however, markets are routinely less than ideal or perfect. Often suppliers do have at least some degree of control over the price. When this control is relatively modest, as with many markets, no corrective action is required or taken. For example, if a manufacturer can raise and maintain the market price ten percent above a competitive level, the full weight and force of the U.S. Department of Justice and the Federal Trade Commission are not likely to be used to correct this market imperfection. Indeed, the corrective action may cause more harm than good by deterring new entrants or imposing additional compliance costs. Also, with low entry barriers, over time the higher price will draw the attention of potential new suppliers who will drive the price down closer to the competitive level when they enter the market. Problems arise when the price control is relatively large and has persisted, or has the potential to persist, for a long time.

The ability of a supplier or group of suppliers to raise and maintain the price above what would occur in a competitive market is referred to as their market power. Market power is the degree of price leveraging ability a supplier or suppliers have for "price making" ability rather than being a price taker of the perfectly competitive market. The more a firm can charge a price that exceeds its marginal cost and determine what price it wants to charge, the higher the firm's degree of market power.[2] The price-taking competitive firm that has no market power cannot pick its own price or influence it in any significant way. In extreme cases of market power, such as with a monopolist that faces no threat of entry from rival firms, there are upper bound limits on price that even an unregulated monopolist must contend with. These include that the price cannot exceed what consumers are willing to pay for the product (that is, it cannot exceed demand at the quantity the monopolist wants to produce) or charge a price that is sufficiently high that it creates a strong incentive for other firms to find ways around the entry barriers to the market or encourages consumers to seek alternatives.

How much control or price leverage a firm has is based on three factors: the overall demand characteristic of the product, the market concentration or market share of the firm, and the supply characteristics. These three factors together determine how much market power a firm can exercise. No single factor by itself would indicate a firm has considerable market power. For example, if a firm had a substantial market share, say 80 percent of the market, but entry or increased output from other firms was relatively easy and customers had suitable alternatives to the firm's product, then its actual market power potential may in fact be very low.

Unfortunately, in electric markets all three factors clearly play a role. Demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers. Markets are very concentrated for most geographic regions, even for multi-state wholesale regions. And

[2]This can be estimated with the "Lerner Index," which is defined as:

(Price - Marginal Cost)/Price

which measures the markup of price over marginal cost (as a percentage of price). The larger the Lerner Index, the greater the firm's market power. If the Lerner Index equals 0.5, then 50 percent of the price is the mark-up above marginal cost; if it equals 0.02, then just two percent of the price is mark-up above marginal cost. If the Index equals 0.5, it may indicate significant market power and require some action; if it is only 0.02, it is unlikely to raise any calls for governmental action.

market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. As economic theory would predict, because during peak hours supply is often very inelastic, that is, the quantity supplied is not very responsive to the price, markets are relatively concentrated, and demand is also very inelastic, market power has been very significant, particularly during peak hours.

The way a supplier can exercise market power in electric power markets, if they have some degree of price leverage,[3] is to either physically or economically withhold output from the market. Physical withholding is the actual withdraw of capacity, such as claiming that a plant or plants are down for maintenance or withdrawing capacity for other reasons. Economic withholding is bidding a relatively high price with the expectation that either the plant or plants will not be selected for dispatch, or if they are selected, the owner will receive a much higher price than the marginal cost. In either case, withholding is profitable because the revenue lost from the idled capacity is more than made up for by the increased revenue gained by the operating plants that receive the higher price. As will be discussed below, both withholding strategies appear to have been used in California.

Since an attempt is being made to develop competitive markets to replace decades of states and federal regulation, it is generally assumed that these markets will require both time to develop and frequent adjustments when problems are encountered. Therefore, it is unlikely that idealized, perfectly competitive markets would develop immediately. However, market power has either been detected by market analyses (estimated by quantitative methods) or alleged by supplier behavior in all the markets discussed below. Given the characteristics of electricity demand, supply, and the concentrated nature of power markets, this market power may persist for some years to come.

[3]If a firm has no or very little market power, then raising the price will mean the loss of all or a substantial number of the firm's customers.

California

The California Power Exchange (PX) began operation in April of 1998 and ran relatively uneventfully for two years. The average PX price (April through December) was \$26/MWh in 1998 and was \$31/MWh during 1999. California's problems began in May of 2000 when the average PX price jumped to \$50/MWh and then to \$132/MWh in June–on its way to a high of \$385/MWh in December 2000.

The first direct impact of the wholesale price increases was felt by San Diego Gas & Electric (SDG&E) customers. SDG&E had finished recovering generation asset "transition costs" early (before the 2002 deadline set by legislation) and thus had ended its mandated rate discount and rate freeze for residential customers. Customer generation prices were based directly on the California PX–as it was during the transition period– but without the rate cap. As a result, customers' bills doubled and later that summer tripled from what they had been earlier in the year. This garnered national attention that has continued up to this day.

The now infamous higher wholesale prices in California (Figures 9 and 10) resulted from a combination of factors that can be put into four general categories: (1) strong demand and load growth, (2) supply constraints, (3) production costs increases, and (4) wholesale and retail market design flaws. Together these factors produced an unfortunate combination of factors that aligned in *Perfect Storm* fashion to cause soaring prices. As noted above, the characteristics of electricity supply and demand suggests that suppliers would have substantial market power under usual conditions. The tight supply conditions and the market design flaws in California, however, contributed to an extreme environment for market power. The next section will discuss specific findings of supplier market power.

Due to strong economic growth and an increasing population, California's peak demand increased by 12 percent from 1996 through 1999. Also, relatively high summer temperatures contributed to a 13.7 percent load growth from June 1999 to June 2000. Electricity demand increased by 5 percent the first eight months of 2000 relative to the same period in 1999 (Wolak, Nordhaus, and Shapiro). Peak demand increased by 5,522 MWs from 1996 to 1999, however, only 672 MWs of net capacity was added (EPSA).

Due to long lead times for permitting and siting and resistance from people living near potential plant locations, the process of moving a project from drawing board to producing power can take years or be scuttled completely. Since the crisis, California as streamlined its siting process considerably and new plants are being added.

There was also a significant decrease in net imports into the California ISO throughout the summer of 2000. Scheduled and real time average hourly net energy imports decreased almost 49 percent and 33 percent, respectively, for the period of May through August of 1999 compared to the same period of 2000 (FERC). This drop in net imports was primarily due to an increase in exports from California, which may have been caused by suppliers seeking higher prices outside the state.

Transmission capacity was also constrained, limiting the amount of power moving within the state (from north to south or vice versa) and limiting power flows from outside the state. It takes at least six years to install new transmission lines in California -- three years to plan and site and three years to build (California ISO). Also, fires temporarily knocked out some transmission lines.

Planned and unplanned plant outages increased curiously during the summer of 2000. Average planned megawatts out of service increased by 53 percent in June, 57 percent in July, and 23.5 percent for August when compared to the same months of 1999 (FERC). Unplanned plant outages increased much more dramatically. Average megawatts out-of-service increased by 77 percent for June, 121 percent for July, and 461 percent for August above the same months in 1999. This has prompted some to conclude that there was deliberate withholding of capacity in order to raise the price. This will be discussed below.

There was also a decrease in western states' hydroelectric capacity. Hydroelectric generation in the west decreased by 23.2 percent in June 2000 from the June 1999 level–a decrease of almost 3.9 million MWh (FERC). Because the Pacific Northwest suffered its worst drought in over two decades, there was a general shift throughout the region to typically more costly thermal and other non-hydro generation to meet their load requirements.

In terms of production costs, natural gas prices in California rose from less than $2 per MMBtu in March and April of 1999 to about $5 by September of 2000 and peaked at over $50 in December.[4] Nitrogen oxide (NOx) emission credits for the South Coast Air Quality Management District (SCAQMD) in the Los Angeles basin increased from about $6.00 per pound in May of 2000 to about $45 per pound in September and remained relatively high through the rest of 2000.

FERC staff reports that the increase in natural gas and NOx emission credit prices raised the marginal running cost of a combined cycle generation unit with a heat rate of 10,000 Btu/kWh and a NOx emission rate of 1 lb/MWh by approximately $64.00 per MWh – from $26.00 to $90.00 per MWh. EPSA calculates the combined cost of fuel and NOx credits for a gas peaking unit in the LA Basin at approximately $147/MWh. Even a very generous assumption of a total operating and capital costs of $60 per MWh, puts the total cost at $207 per MWh ($60 plus $147). As can be seen from Figure 9, the weighted *average* price in December 2000 and January 2001 greatly exceeded that cost. During peak hours, Figure 10 shows that the price often exceeded $300 per MWh in those months.

A number of flaws in California's power market design have also been cited as contributing factors. First, suppliers had an incentive to shift power from the PX to sell in the ISO's real-time energy and ancillary services markets at peak times. This reduced the available capacity in the PX even further and drove the price even higher. A second possible factor was the utility distribution companies' (UDCs') PX purchase and sale requirement. This may have, combined with fear of a retrospective review by the California Commission, discouraged forward and long-term contracting by UDCs. One UDC was entirely in the spot market and the other two major UDCs were only using long-term contracts sparingly. The UDCs were also likely expecting that their spot market purchases would be completely recoverable–something that was assured when wholesale prices

[4]There have been allegations that prices in western natural gas markets are due to at least some natural gas producer and marketer market power as well.

were falling or steady. But because of the retail price caps, the UDCs where unable to pass the higher wholesale costs through to retail customers. As a result, they accumulated about $14 billion in uncollected expenses. This drove one UDC, PG&E, into bankruptcy and financial difficulties for another UDC, Southern California Edison.[5] Since suppliers were unwilling to sell to the financially troubled UDCs (exacerbating the shortage), the state of California began purchasing wholesale power for UDC customers in January 2001 (Figure 11 and 12).

Lack of demand response because of the retail price constraints is also cited as a contributing factor since it prevented the higher wholesale price from being passed through to retail customers–who would then reduce their quantity of power demanded. In San Diego, where customers received the full brunt of the wholesale prices increases for several months, some demand response was seen. However, price constraints were reapplied by legislation in September 2000. This year, California increased rates for some customers considerably, and the effects of that are perhaps also beginning to be seen. It will take time, however, to separate out the price effect on quantity demanded and the impacts of weather, a slowing state economy, and other factors.

The California wholesale market power problem is a western states' wholesale problem as well. The higher wholesale prices have spread throughout the western states, prompting FERC to issue a price cap on the entire 11 state western region. On June 18, 2001, FERC unanimously ordered “market-based” price mitigation on spot market wholesale prices across the 11-state Western power market. During emergency supply periods in California (when reserves are below 7 percent), the price ceiling will be based on the California ISO market clearing price. During non-emergency periods, the cap will drop to 85 percent of the emergency period price. The cap may be exceeded with justification. The price mitigation will end on September 30, 2002.

---

[5]To help relieve the financial strain on Southern California Edison, the state of California is considering a plan that would have the state purchase the company’s transmission system for several billion dollars.

California Market Performance

Not surprisingly, the California power market has been studied and analyzed more than any other power market in the country. An important question is: was the price increase due only to tight supply conditions to meet the growing demand or was some portion due to supplier market power? A price increase due to scarcity (causing the increased use of marginally more expensive generating units) can be separated from an increase due to market power. Evidence before the summer of 2000 suggested that market power was significant during peak hours and that the higher prices were due to a combination of scarcity *and* supplier market power. As noted, since growing demand in California was not matched with additional supply, there is little doubt that scarcity played a role in the California crisis. What would be expected is that the price would be driven up to the marginal cost of the highest cost marginal unit needed to satisfy demand–a higher marginal cost than would obtain than during times of relatively plentiful supply. However, it is clear that actual prices exceeded, often greatly exceeded, the expected higher marginal cost. The evidence of market power is based on several analyses of the California market.

Before the California crisis of 2000 began, a study by Borenstein, Bushnell, and Wolak[6] had found evidence of significant market power in the California wholesale electricity market. They estimated total payments in excess of competitive levels at $719 million for the 16 months of their study period–June of 1998 to September of 1999. If June of 1998 is excluded, the total payment in excess of competitive levels was determined to be $795 million. They calculated the average markup of price over a competitive outcome at 15.7 percent or, excluding June '98, 18.3 percent. This markup occurred primarily during peak demand periods.

[6]Borenstein, Bushnell, and Wolak, “Diagnosing Market Power in California’s Deregulated Wholesale Electricity Market,” working paper of the Program on Workable Energy Regulation, University of California Energy Institute, Berkeley, California, March 2000, PWP-064.

An analysis by Frank Wolak,[7] Chairman of the California ISO's Market Surveillance Committee, estimated that the market power markup was only 1.2 percent of the total wholesale price in 1998 and averaged nine percent of the price in 1999. For the period of June 2000 through January of 2001, however, the average markup was estimated at 45 percent and peaked during this period at 64 percent of the price in August. In dollar terms, the largest markup occurred in January of 2001 at $130/MWh–when the average monthly price was $305/MWh. These findings are summarized in Figure 15.

Anjali Sheffrin, the Director of the Department of Market Analysis of the California Independent System Operator, conducted a detailed analysis of market power and bidder strategy in California. [8] This study provides evidence that "many large suppliers actively engaged in strategic bidding efforts and that their activity had a direct impact on market prices." Dr. Sheffrin concludes that supplier "bidding strategy was not ad hoc, but consistent with a certain model of oligopoly pricing behavior" and that it "implies the systematic exercise of market power to maximize profit." Her findings are consistent with expected behavior of firms with considerable market power that can profitably use economic and physical withholding to raise prices. Five large in-state suppliers were found to use economic withholding 80 percent of the time and physical withholding less than 20 percent of the time. Her estimated average bid-cost markup was more than $100/MWh during some summer months. The total market power impact was estimated at approximately $6.2 billion from May of 2000 through February of 2001.

[7]Frank A. Wolak, "What Went Wrong with California's Re-structured Electricity Market? (And How to Fix It)," Department of Economics, Stanford University, Stanford, CA, http://www.stanford.edu/~wolak.

[8]Anjali Sheffrin, "Empirical Evidence of Strategic Bidding in California ISO Real Time Market," March 21, 2001, California Independent System Operator and "What Went Wrong With California Electric Utility Deregulation?," presentation at "Current Issues Challenging The Utility Industry," held by the Center for Public Utilities, New Mexico State University, Santa Fe, New Mexico, March 26, 2001.

An analysis by Joskow and Kahn,[9] concludes that wholesale electricity prices in California "far exceeded" competitive levels from June through August of 2000. They could not explain the prices as the "natural outcome of 'market fundamentals' in competitive markets." This was due to the "very significant gap between actual market prices and competitive benchmark prices that take account of these market fundamentals." They estimate a competitive benchmark price of $62.6 per MWh for June 2000 (assuming a NOx price of $10/lb) that compares with the average PX price for the month of $120.2 per MWh. For July the competitive benchmark was $67.98 per MWh ($20/lb NOx price) and a average PX price of $105.72 per MWh. August and September competitive benchmark prices were $121.5 and $104.36 per MWh (both using a NOx price of $35/lb) respectively, when average PX prices were $166.24 in August and $114.87 in September. The market fundamentals accounted for in their analysis included higher natural gas and emission permit prices, increased demand, and reduced availability of imports. They also found evidence that suggests that the higher prices reflected the withholding of supplies by generators and marketers.

[9]Joskow and Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," an AEI-Brookings Joint Center for Regulatory Studies Working Paper (01-01), January 2001.

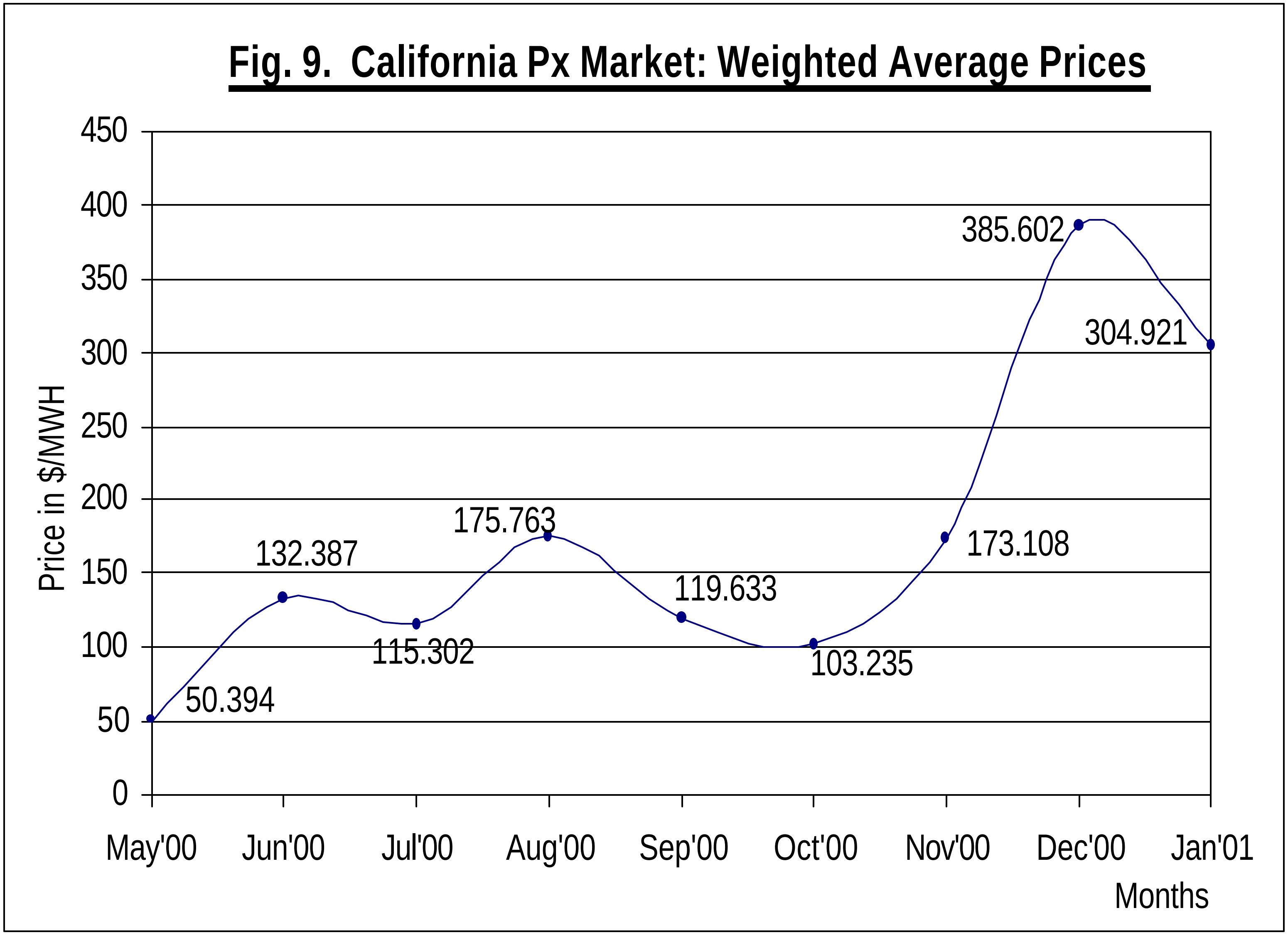


Fig. 9. California Px Market: Weighted Average Prices
Price in $/MWH
450
400
350
300
250
200
150
100
50
0
50.394
132.387
115.302
175.763
119.633
103.235
173.108
385.602
304.921
May'00
Jun'00
Jul'00
Aug'00
Sep'00
Oct'00
Nov'00
Dec'00
Jan'01
Months

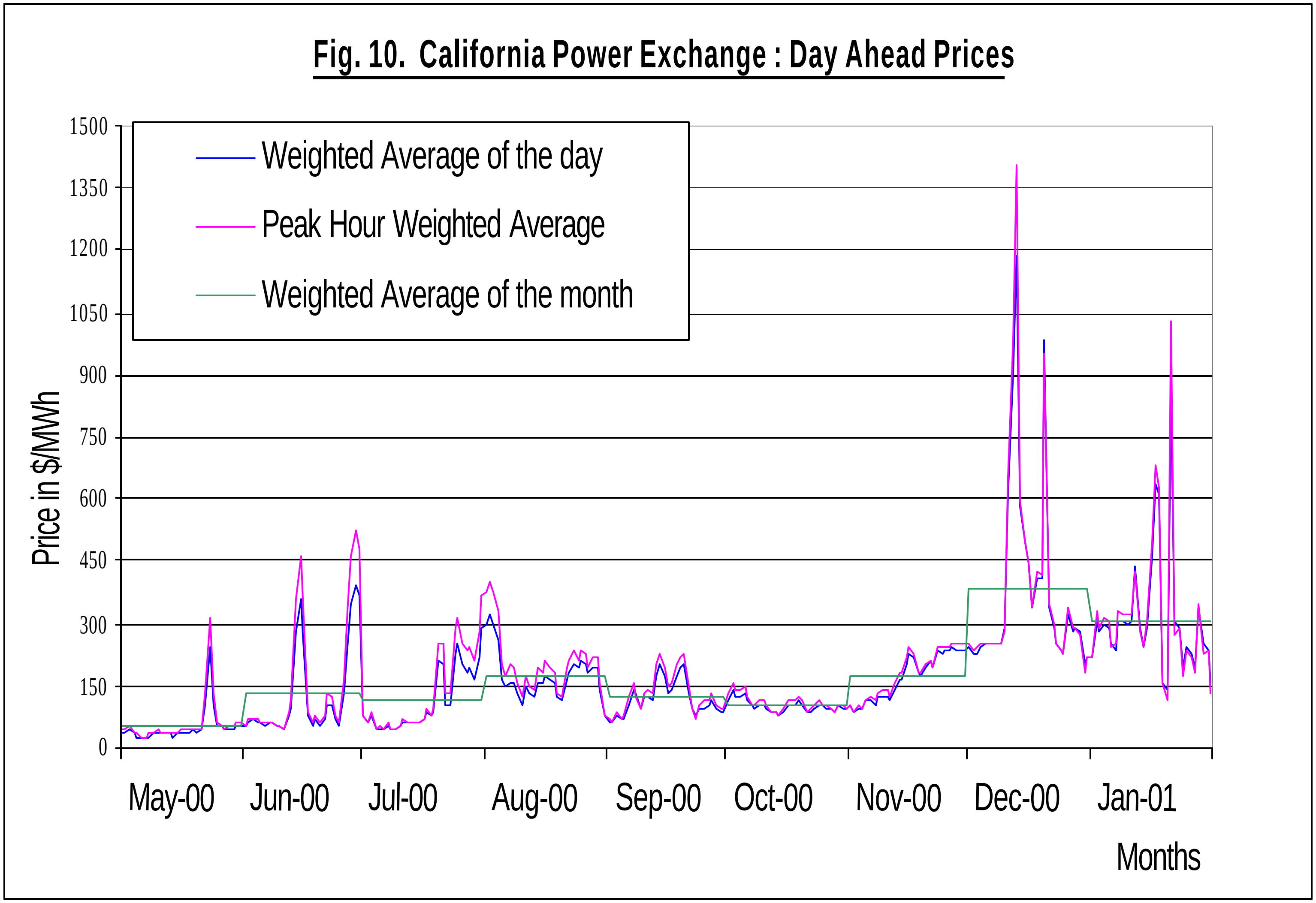


Fig. 10. California Power Exchange : Day Ahead Prices
Weighted Average of the day
Peak Hour Weighted Average
Weighted Average of the month
Price in $/MWh
1500
1350
1200
1050
900
750
600
450
300
150
0
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Months

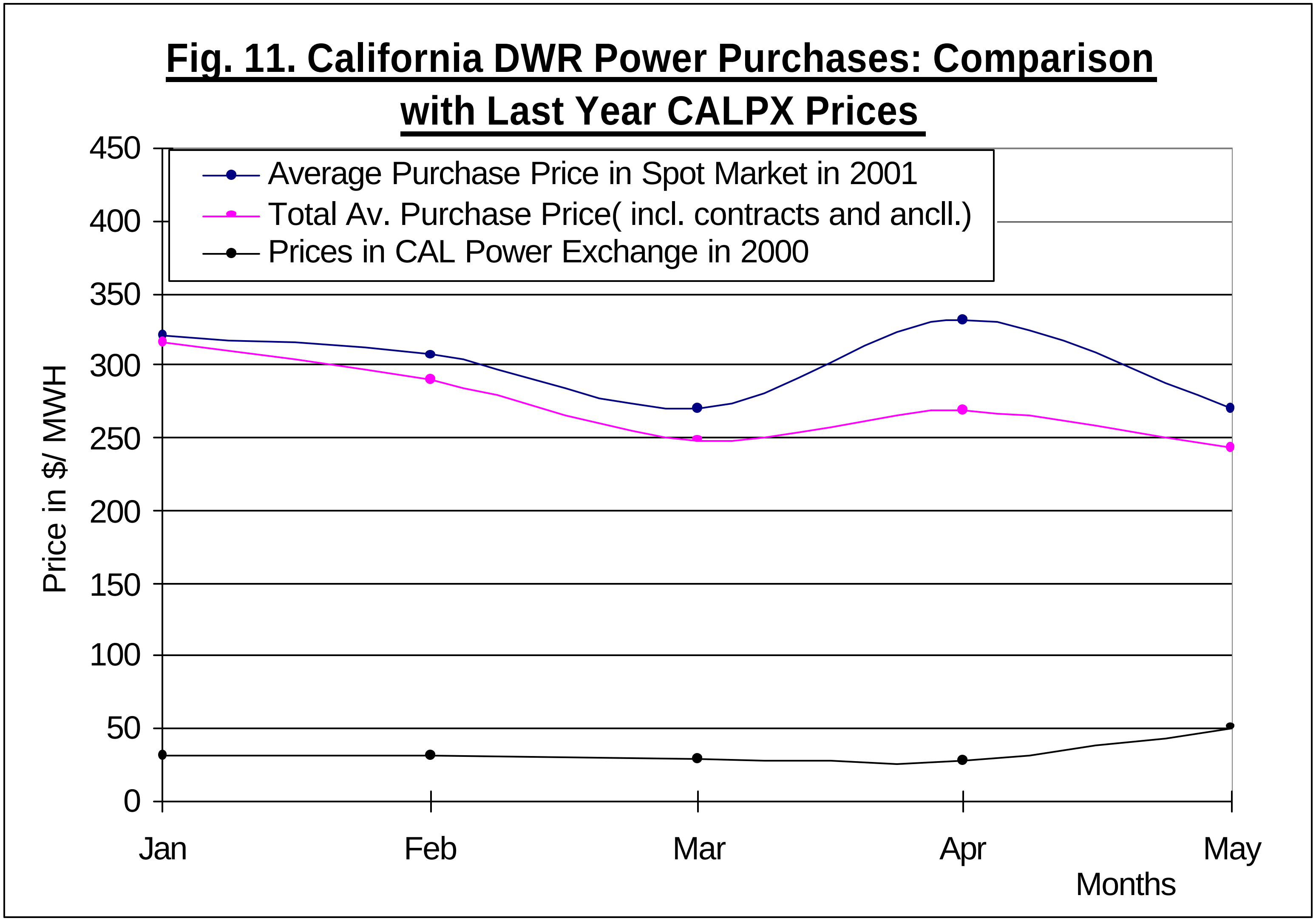


Fig. 11. California DWR Power Purchases: Comparison with Last Year CALPX Prices
Average Purchase Price in Spot Market in 2001
Total Av. Purchase Price(incl. contracts and ancll.)
Prices in CAL Power Exchange in 2000
Price in $/ MWH
450
400
350
300
250
200
150
100
50
0
Jan
Feb
Mar
Apr
May
Months

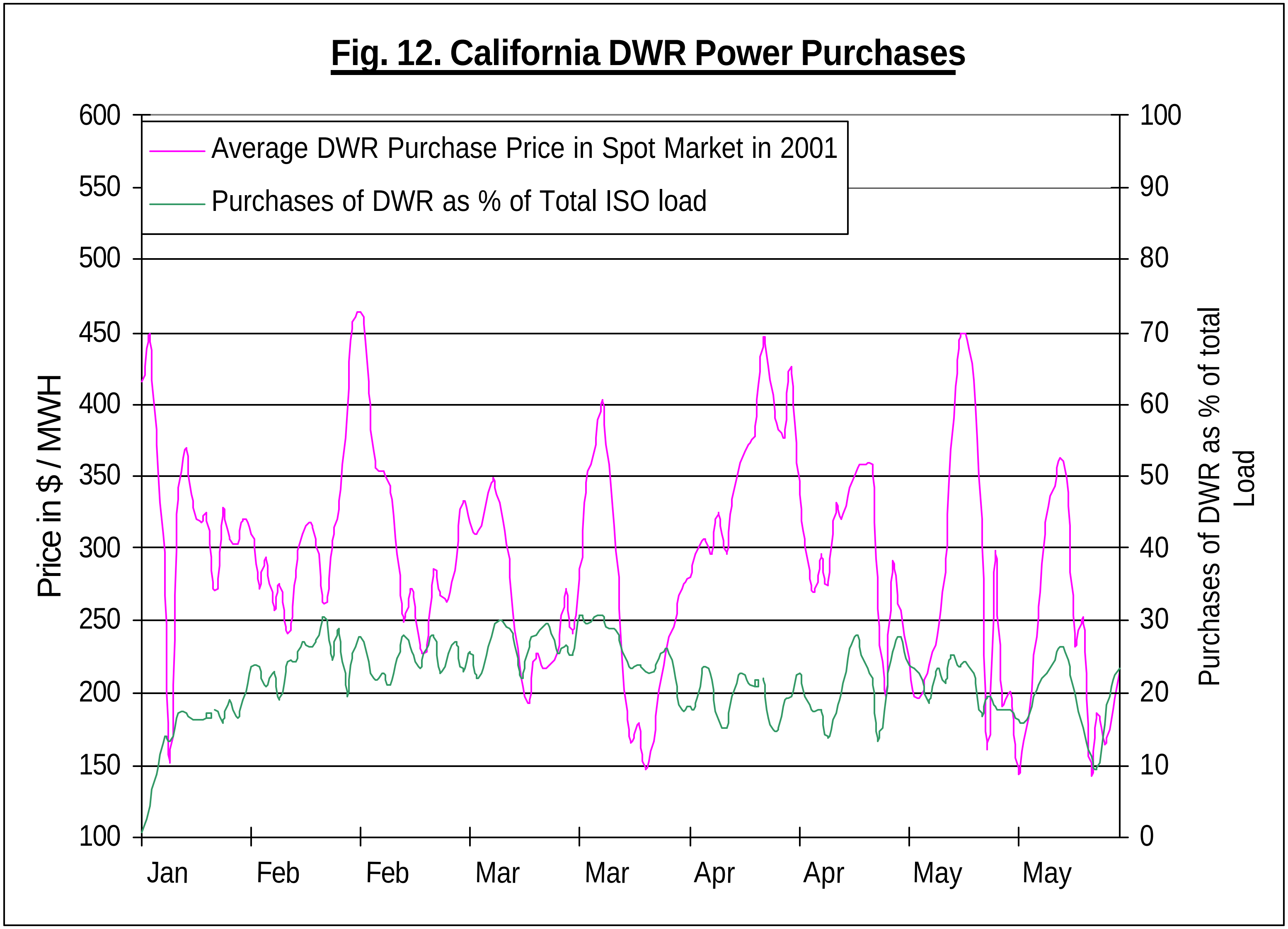


Fig. 12. California DWR Power Purchases
Average DWR Purchase Price in Spot Market in 2001
Purchases of DWR as % of Total ISO load
Price in $ / MWH
Purchases of DWR as % of total Load
600
550
500
450
400
350
300
250
200
150
100
100
90
80
70
60
50
40
30
20
10
0
Jan
Feb
Feb
Mar
Mar
Apr
Apr
May
May

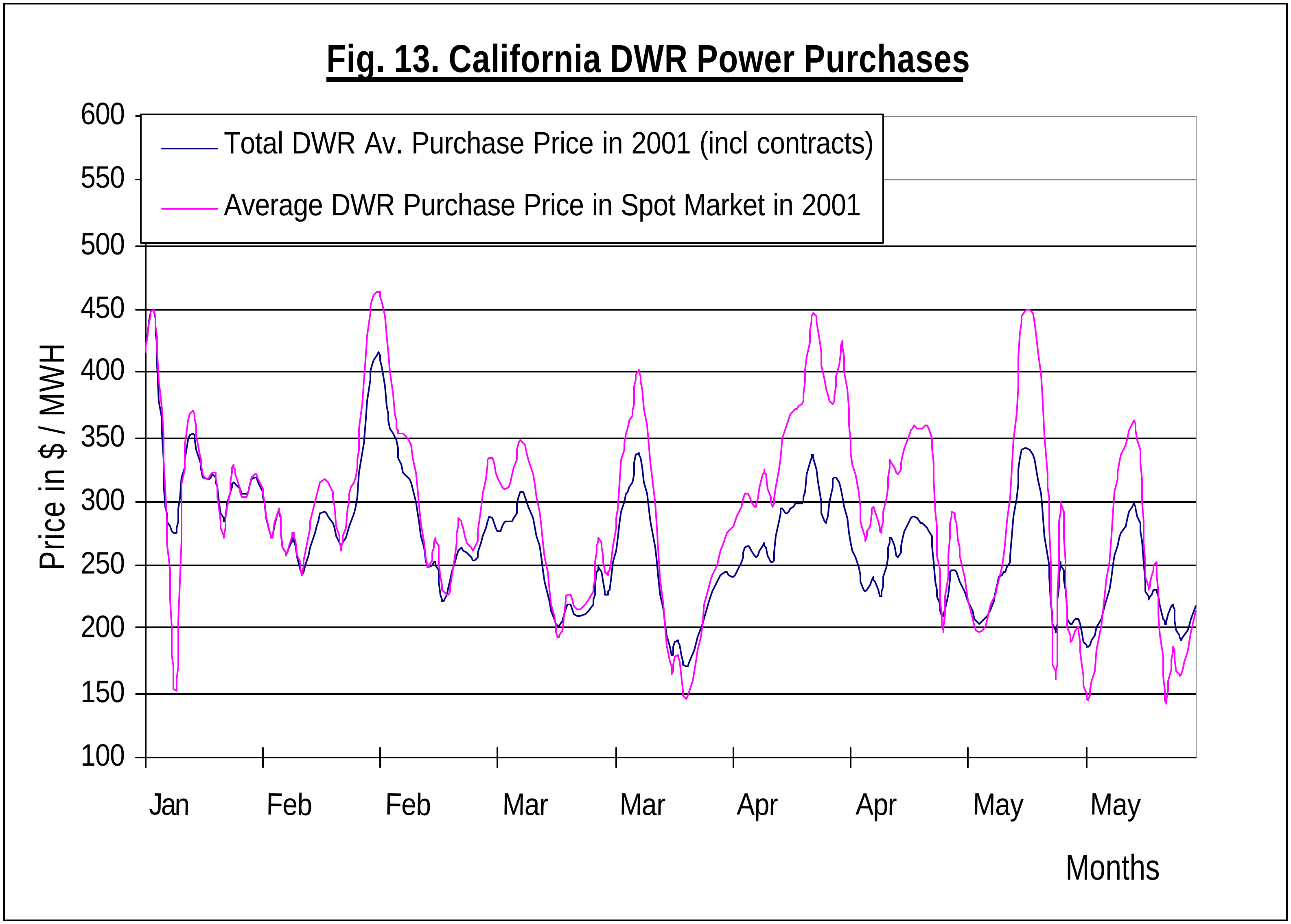


Fig. 13. California DWR Power Purchases
Total DWR Av. Purchase Price in 2001 (incl contracts)
Average DWR Purchase Price in Spot Market in 2001
Price in $ / MWH
600
550
500
450
400
350
300
250
200
150
100
Jan
Feb
Feb
Mar
Mar
Apr
Apr
May
May
Months

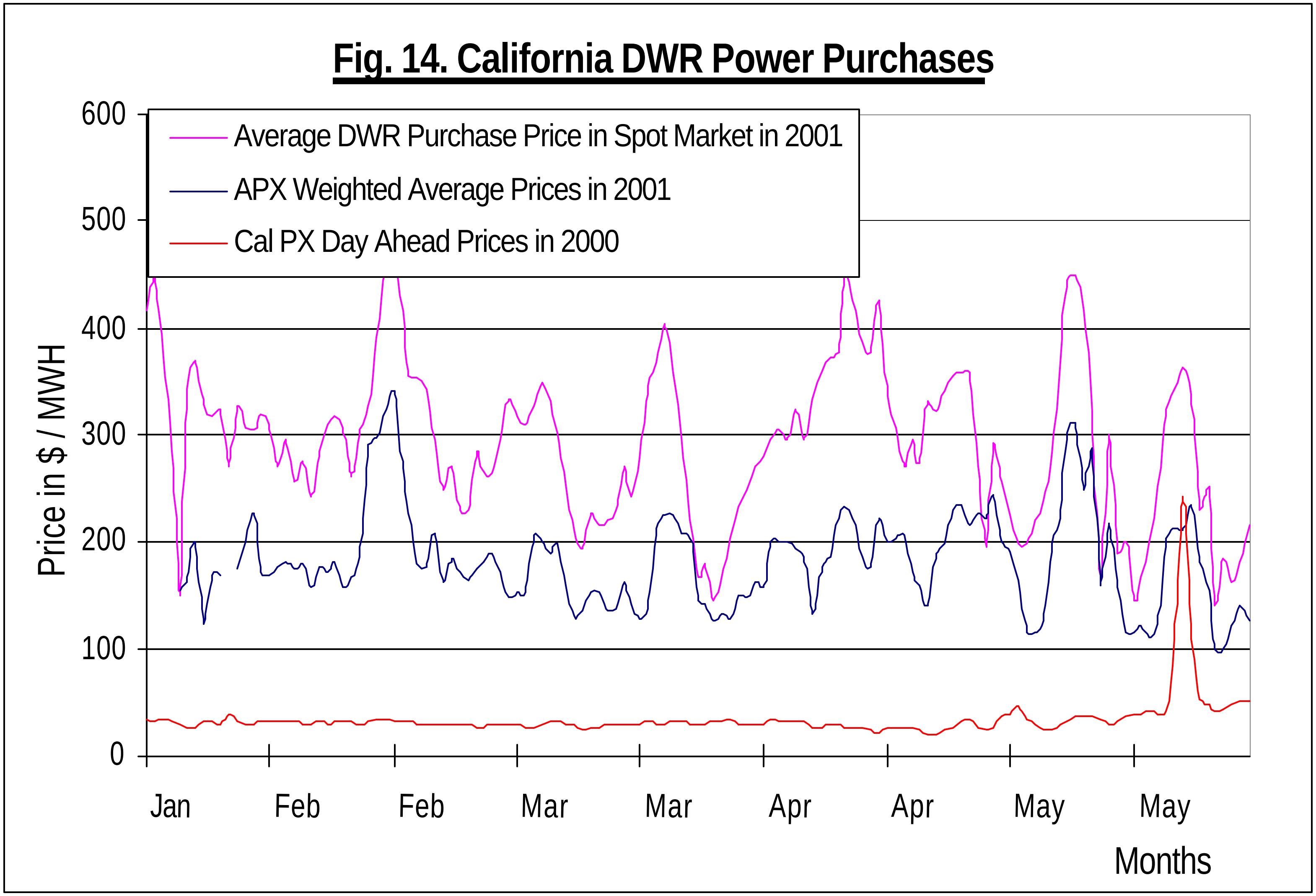
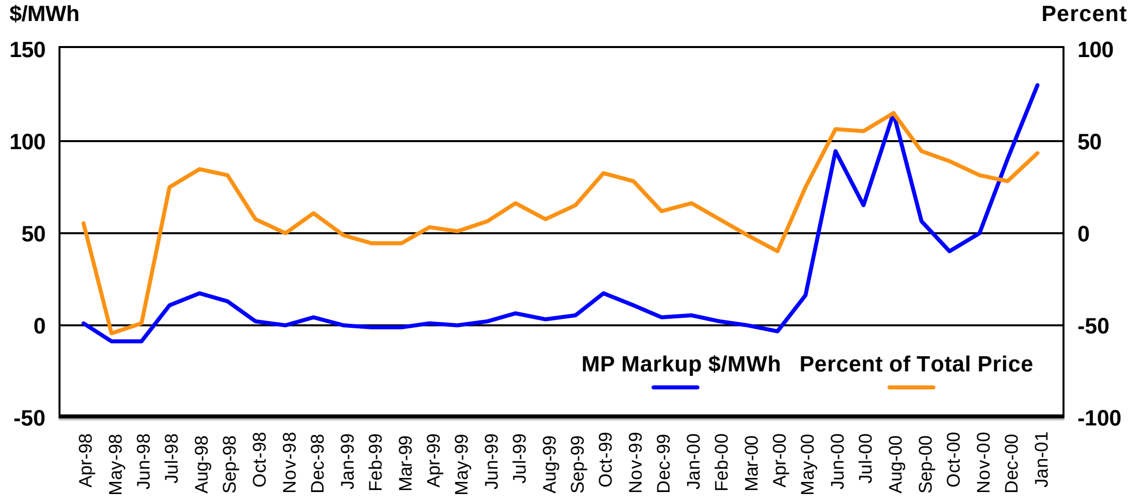


Fig. 14. California DWR Power Purchases
Average DWR Purchase Price in Spot Market in 2001
APX Weighted Average Prices in 2001
Cal PX Day Ahead Prices in 2000
Price in $ / MWH
600
500
400
300
200
100
0
Jan
Feb
Feb
Mar
Mar
Apr
Apr
May
May
Months

Figure 15. Average Market Power Markup and Percent of Wholesale Price in California.



Time Period	MP markup ($/MWh)	Percent of Total Price
1998	3.5	1.2
1999	3.8	9
2000	44	30
Jun 00 - Jan 01	80	45
Aug 2000	116	64
Jan 2001	130	43

Source: Frank A. Wolak, "What Went Wrong with California's Re-structured Electricity Market? (And How to Fix It)"

New England

NEPOOL moved to a competitive bid based dispatch system on May 1, 1999.

New England Market Performance

A study by Allen, Biewald, and Schlissel,[10] found that during the first 12 months of an open wholesale generation market (May 1, 1999 - April 30, 2000), 47 percent more capacity was out of service (on an average weekday) than during the prior 12 month period and nearly double that of May 1997 through April 1998. Also, fossil plant forced outage rates increased from 11.4 percent, during January 1997 to April 1999, to 23.6 percent for the period May 1999 to December 1999. On May 8, 2000, the peak market clearing price reached $6,000/MWh when 8,440 MW was out of service–a 66 percent increase relative to the average daily capacity out of service during the same month in the three years prior to competition. On June 8, 1999, the peak market clearing price reached $1,003/MWh when 5,965 MW was out of service -- a 83 percent relative increase.

ISO New England issued two brief papers to provide information on the events of May 8 and 9, 2000.[11] They noted that New England and other northeast control areas “experienced record breaking temperatures that resulted in extremely high loads for early May.” The ISO stated:

> . . . ISO New England reviewed the prices being posted on the New York ISO web site . . .. Those prices ranged from a low of approximately $77 per MWh to a high of approximately $1,453 per MWh. In other hours, when the ISO was not purchasing emergency [power] from New York, the New York integrated hourly price was as high as $3,387 per MWh. These prices caused the ISO to conclude that the $6,000 per MWh price was reasonably

---

[10] Allen, Biewald, and Schlissel, "Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Markets," paper prepared for the Union of Concerned Scientists, Cambridge, MA, Jan. 7, 2001.

[11] “Events of May 8 and 9, 2000" and Supplemental Report on May 8, 2000,” from ISO New England’s web site.

related to the costs and risks faced in securing and arranging delivery of energy to New England.

The ISO stated that it conducted a detailed review and determined that the operation of both the markets and the power system were in accordance with the current rules and procedures. No mention is made as to whether any attempt was made to determine actual supplier marginal cost at those hours when the $6,000 price was obtained, whether they detected any strategy to economically or physically withhold capacity from the market at that time, or whether strategic bidding by suppliers was detected. It is difficult to construct a scenario where $6,000/MWh ($6/kWh) would be an actual marginal cost from any generation source in any region of the country.

To date, there has not been a comprehensive assessment of market power in New England, however, a study is currently underway and is expected soon.

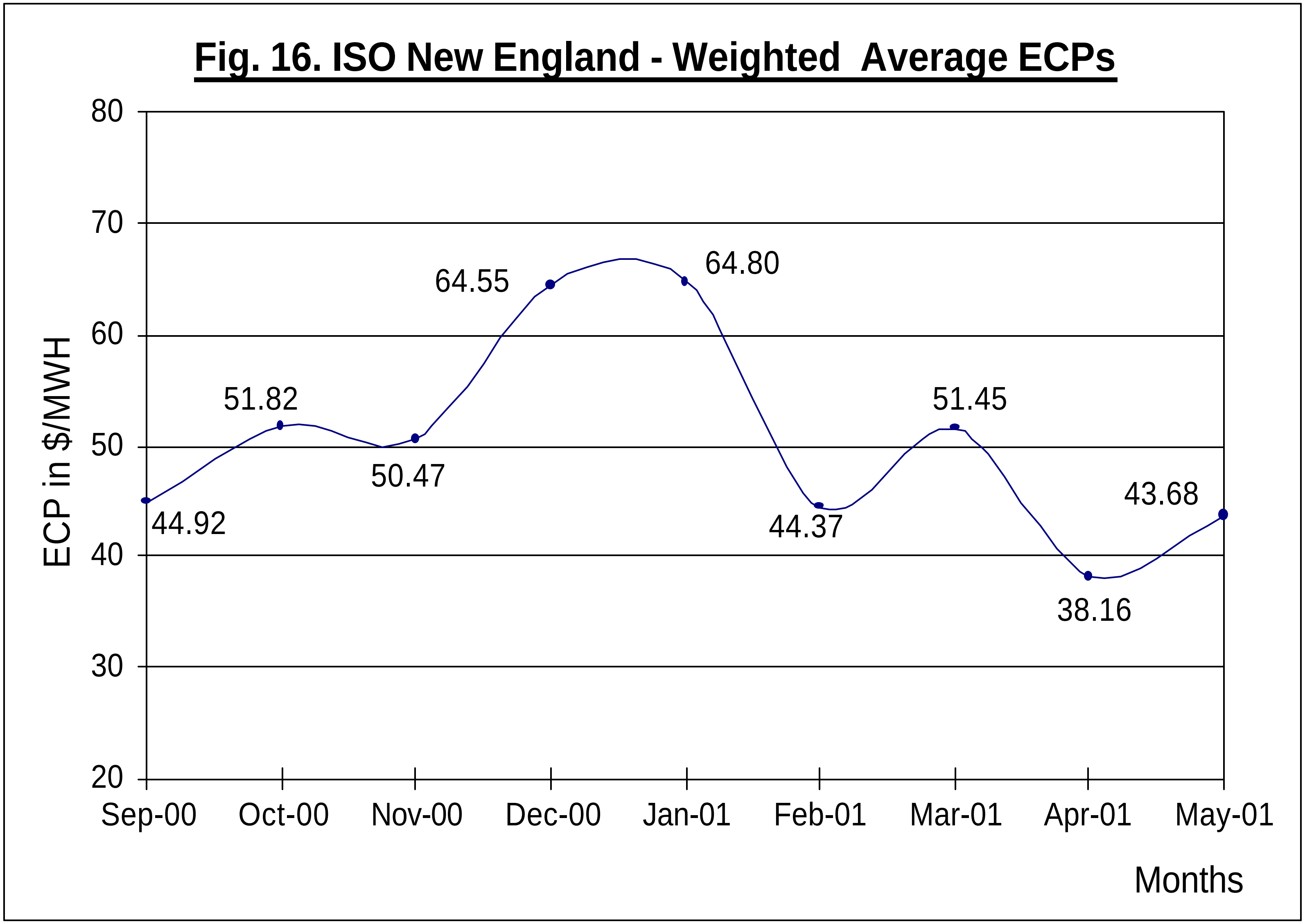


Fig. 16. ISO New England - Weighted Average ECPs
80
70
60
50
40
30
20
ECP in $/MWH
64.55
64.80
51.82
51.45
50.47
44.92
44.37
43.68
38.16
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Months

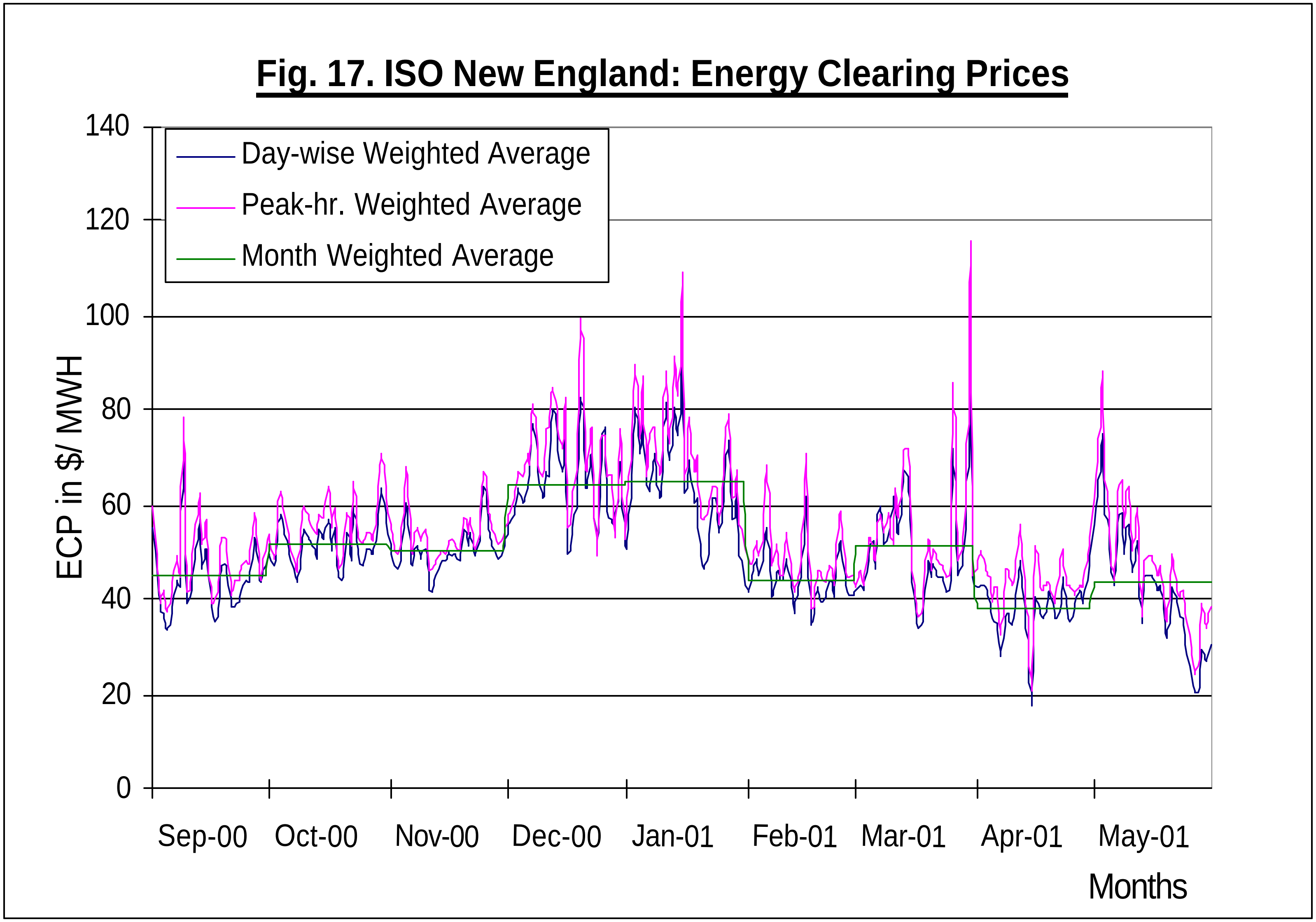


Fig. 17. ISO New England: Energy Clearing Prices
Day-wise Weighted Average
Peak-hr. Weighted Average
Month Weighted Average
ECP in $/ MWH
140
120
100
80
60
40
20
0
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Months

PJM

PJM operates six markets: day ahead energy market (June 1, 2000), real time energy market (April 1, 1999), daily capacity markets (January 1999), monthly and multi-month capacity markets (January 1999), regulation market (June 1, 2000), and Fixed Transmission Rights (FTR) auction market (May 1, 1999).[12]

PJM Market Performance

The Market Monitoring Unit of PJM recently released their assessment of the PJM markets in 2000.[13] Overall, they conclude that in 2000, energy and capacity markets were "reasonably competitive" and the regulation market and the FTR auction were "competitive." Their assessment states:

> The MMU also concludes that there are potential threats to competition in the energy, capacity and regulation markets that require ongoing scrutiny and in some cases may require action in order to maintain competition. Market participants do possess some ability to exercise market power under certain conditions in PJM markets.

Specifically, their assessment calculates a "price-cost markup index," basically a load weighted Lerner Index (defined in footnote 2 above). From April of 1999, the beginning of the competitive energy market, throughout the remainder of the year, the average markup was about 0.02 (2 percent of the price), with the maximum for the year in July at 0.08 (8 percent). In 2000, the average markup increased to 0.04 (4 percent), with the maximum in December at 0.14 (14 percent). This is modest, of course, in comparison to California's markup of 0.45 (from Figure 15, where it was expressed as 45 percent of

---

[12] Joseph E. Bowring, "Market Issues in PJM," presentation at NRRI Market Power Conference, April 10, Columbus, OH.

[13] "PJM Interconnection State of the Market Report 2000," Market Monitoring Unit, PJM Interconnection, June 2001.

the total price) for June 2000 through January 2001.[14] However, there was an increasing trend in the markup throughout most of 2000 and at its highest point, that is, December 2000 at 0.14 (14 percent), it is high enough to warrant some concern.

For the capacity market, PJM's Market Monitoring Unit concluded that there does not appear to be market power or market manipulation in the observed prices in the summer months. They caution, however, that:

> [d]espite these conclusions regarding 2000, conditions in the capacity credit markets make the potential exercise of market power a continuing concern. Demand is extremely inelastic since it is a function of 12-month historic loads and PJM's capacity requirement rules. There were only a few generation owners who had excess capacity and were therefore in a position to sell capacity. Even with more generators offering capacity into the market, economic theory suggests that significant market power may exist in the presence of the low demand elasticity that characterizes the capacity markets.

Capacity credit prices have varied widely throughout the year.[15] The weighted average price for combined daily, monthly, and multi-monthly capacity credit ranged from about \$20/MW-day (for December) to \$179/MW-day[16] (for July) during 2000. Daily prices for capacity credits ranged from \$0.02/MW-day to \$238/MW-day for December and July, respectively. For 2001, the posted monthly prices for capacity credits are, with one exception, about \$160/MW-day or greater and reached a high of \$299/MW-day. The daily credit prices show wide fluctuations between zero and \$350/MW-day. On December 31, 2000 the price was zero, the next day, January 1, 2001, the price went to \$177/MW-day.

---

[14]While the PJM markup calculation is similar to Wolak's shown above, they are not exactly the same, so comparison is just a rough approximation for illustration purposes only.

[15]All "load serving entities" in PJM must have capacity commitments in the form of their own capacity or purchase capacity credits from others that have capacity available to sell.

[16]PJM's MMU notes that a capacity market price of \$160/MW-day is equivalent to a net energy price differential of \$10/MWh for a 16-hour forward market standard energy contract–after the cost of transmission.

After holding steady at about that level, the daily price then dropped off during April and fell to zero again last May.

Given this variation and price level in the capacity market, combined with the energy market prices and variation shown in Figures 16 and 17, it is easy to see why the retail markets in Pennsylvania and other PJM states have sputtered recently, as described in Part I. The highest "shopping credit" or price to compare for generation service in Pennsylvania is in PECO Energy's territory, at 5.67 cents/kWh.[17] When energy prices are over $50/MWh, as it averaged during December of 2000, adding $10/MWh for capacity[18] would place the total cost over $60/MWh or 6 cents/kWh, well above the fixed PECO Energy price to compare. Alternative suppliers that need to secure capacity to serve a retail load in PJM would face a loss of at least 0.33 cents/kWh for each kilowatthour sold. Even when energy prices are in the $30 to $40/MWh range as they averaged from January through May, the margin for a gain would be very thin and risky given the price volatility in both the energy and capacity markets. This also leaves very little room for marketing costs, administrative costs, cost of risk management, or an adequate profit.

In another analysis, Erin T. Mansur[19] found that market imperfections in the PJM spot energy market (which account for 10 percent to 15 percent of the market) for the period April through August of 1999 totaled $224 million. She estimated that total costs in PJM were 41 percent higher than would have occurred with perfect competition. When bilateral contracts are added (an additional 30 percent of the market) the sum of the spot market and bilateral contract costs is $827 million, or a 48 percent increase over competitive costs. She calculated a load-weighted Lerner Index of 0.293 (29 percent of

---

[17]Current annual average price to compare for regular residential service.

[18]The Market Monitoring Unit report states (on p. 44) that "[a] maximum capacity market price of $160/MW-day is equivalent to a net energy price differential of $10/MWh for a 16-hour forward market standard energy contract."

[19]Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," University of California Energy Institute (PWP-083), April 2001.

the price) for the spot energy market and 0.323 (32 percent) when bilateral contracts are included.[20] These are both considerably larger than PJM’s Market Monitoring Unit’s estimate of an average markup of about 0.02 (2 percent) for April through December of 1999 and the year’s maximum markup in July of 0.08 (8 percent). One explanation for this difference may be different calculation methods and data access.

F.T. Sparrow[21] found a similar pattern in PJM to earlier findings in California where the peak price greatly exceeded the marginal cost, but during non-peak times the price was either much closer to marginal cost or even below marginal cost for a few late night and early morning hours. His graph, depicting August and September 1998 weighted average market clearing prices and marginal costs by hour, is shown as Figure 20.

[20]Her methodology is similar to Borenstein, Bushnell, and Wolak, “Diagnosing Market Power in California’s Deregulated Wholesale Electricity Market” and Wolak, “What Went Wrong with California’s Re-structured Electricity Market?”

[21]F.T. Sparrow, State Utility Forecasting Group, Purdue University "Deregulation In Indiana: Is Competition Good or Bad for Indiana Ratepayers?" Electric Power Industry Special Institute, Columbus, Ohio, June 21-22, 2000.

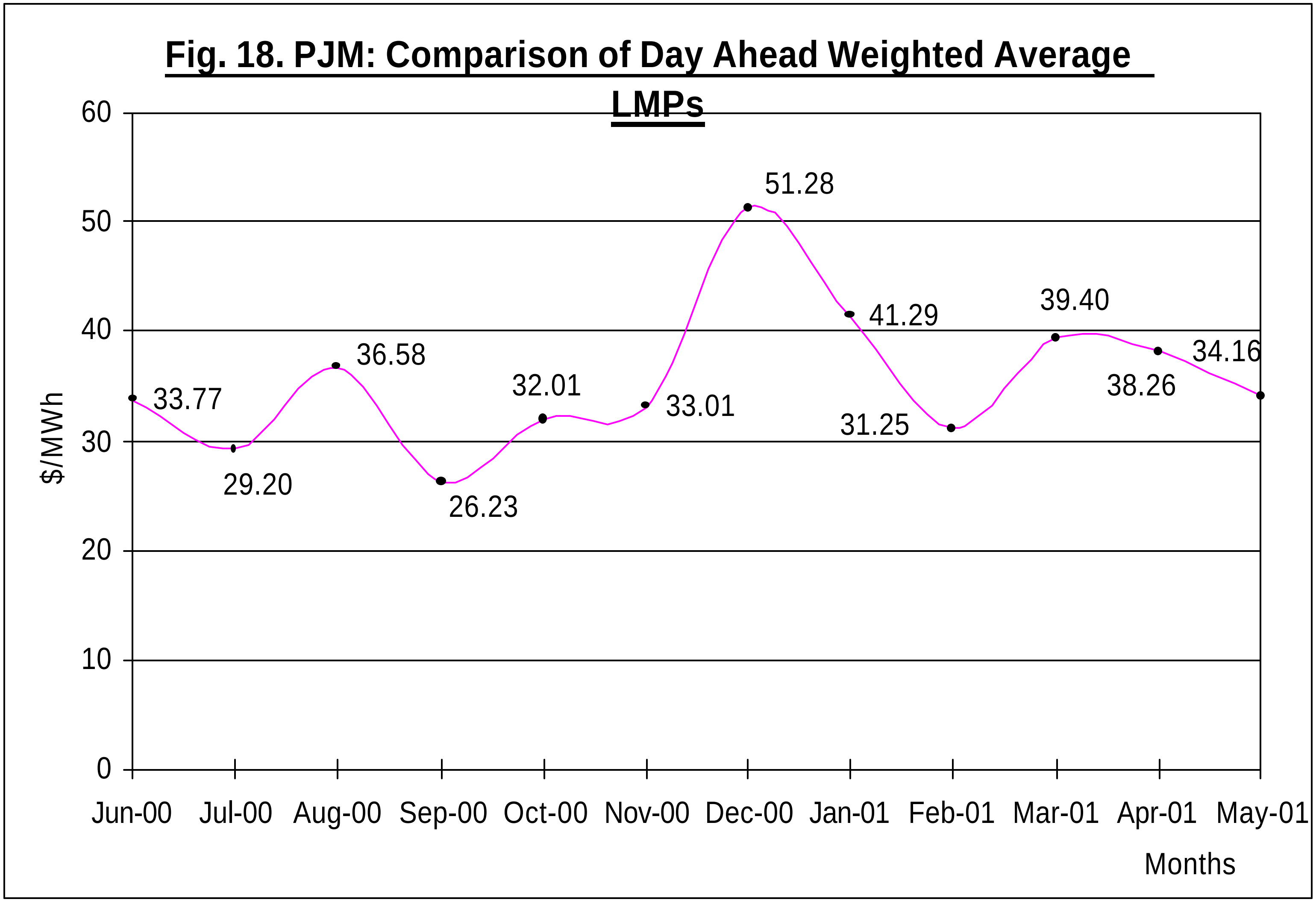


Fig. 18. PJM: Comparison of Day Ahead Weighted Average LMPs
$/MWh
0
10
20
30
40
50
60
33.77
29.20
36.58
26.23
32.01
33.01
51.28
41.29
31.25
39.40
38.26
34.16
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Months

Fig. 19. PJM: Day Ahead Locational Marginal Prices

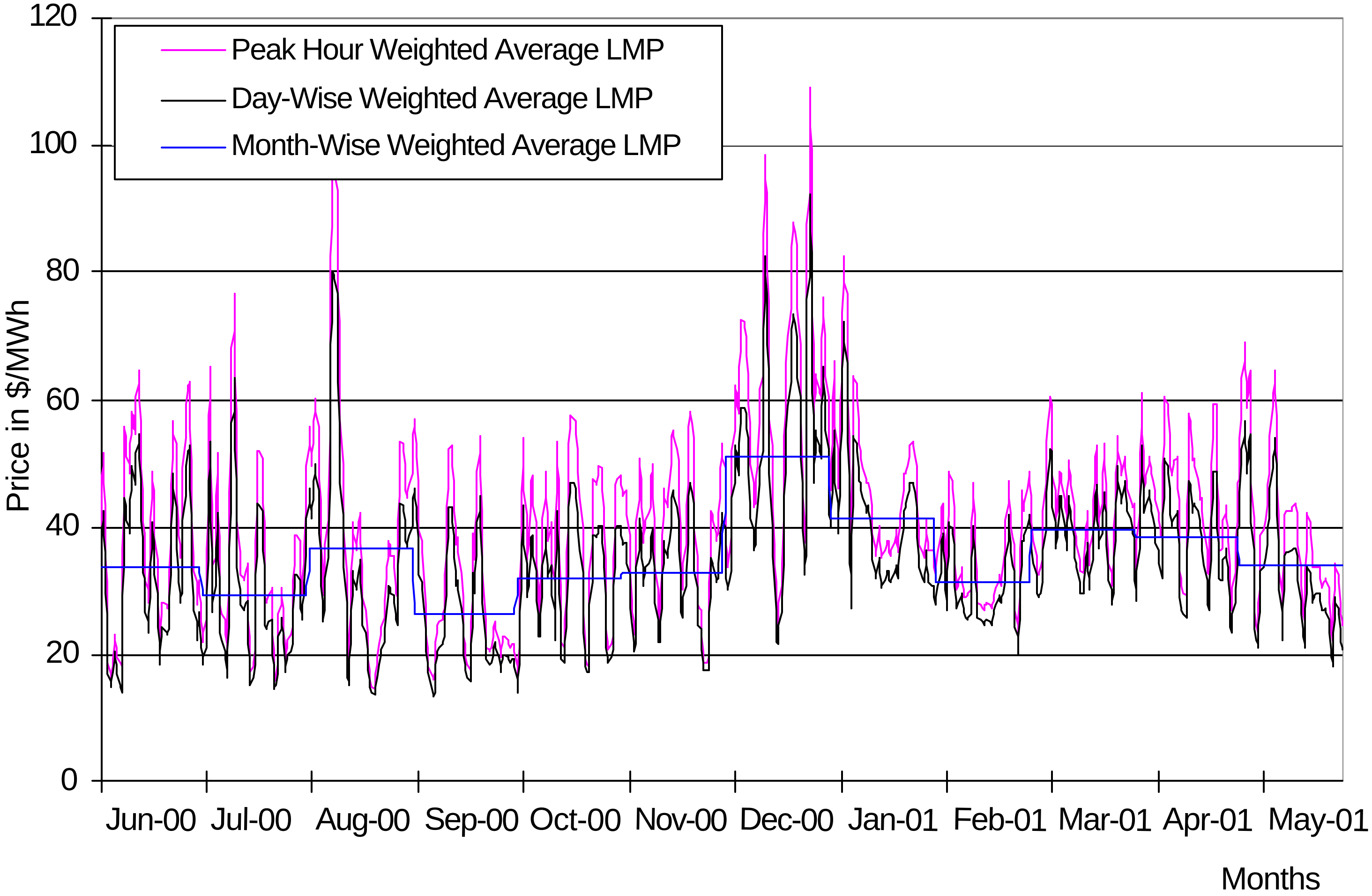
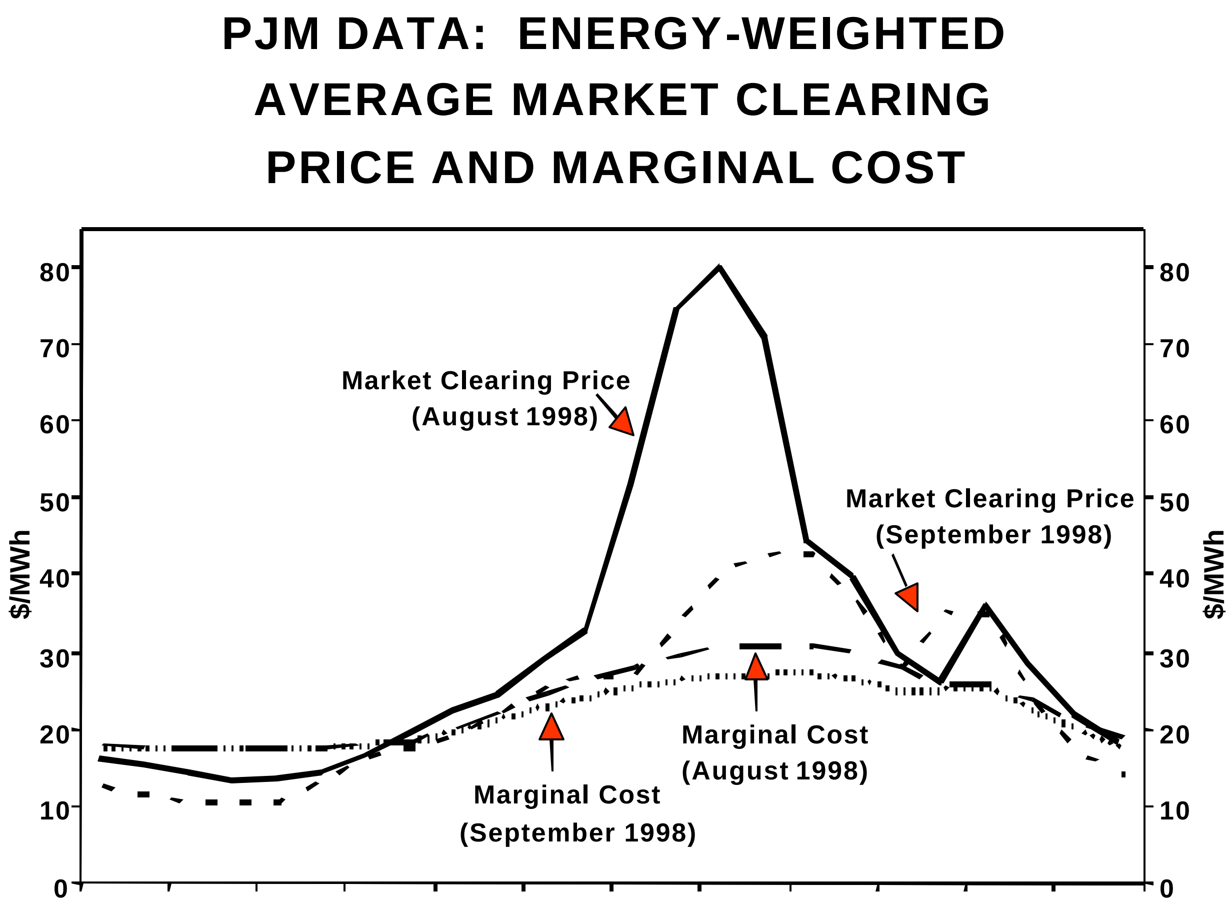


Figure 20.



Source: F.T. Sparrow, State Utility Forecasting Group, Purdue University "Deregulation In Indiana: Is Competition Good or Bad for Indiana Ratepayers?" Electric Power Industry Special Institute, Columbus, Ohio, June 21-22, 2000.

New York

The New York Independent System Operator (NYISO) began operation in November of 1999. The NYISO was built on the infrastructure of the New York Power Pool that preceeded it and simultaneously implemented both day-ahead and real-time energy markets, three operating reserves markets (10-minute spinning reserve, 10-minute non-synchronous reserve, and 30-minute reserve), a regulation market, an installed capability market, and firm transmission rights.[22]

During 2000, the New York City area (Consolidated Edison) had significant retail price increases because of higher wholesale prices. New York City residential customer bills were 20.2 percent higher in June and 42.6 percent higher in July than the same months in 1999. For 2000, customer bills were about 16 percent higher than 1999. Both Consolidated Edison and Orange and Rockland Utilities customer price to compares (or "back-out rate" as its called in New York) are based on the wholesale market, with no overall retail price cap. Therefore, the retail price increases were directly passed through from the wholesale market.

New York Market Performance

The New York ISO Market Advisor[23] found that: "electric markets in New York have been competitive under most conditions experienced to date" and:

- "Except for several isolated instances, the analysis reveals that suppliers bid in a manner consistent with workable competition.
- "These instances can be effectively remedied under the current mitigation measures, and the automated mitigation procedure ("AMP") should effectively address the one day lag in the implementation of mitigation.
- "Lower conduct thresholds for identifying economic withholding do not appear necessary at this point, but further assessments will be made."

---

[22] David B. Patton, "New York Market Advisor Annual Report on The New York Electric Markets for Calendar Year 2000," Capital Economics, April 2001.

[23] David B. Patton, "New York Market Advisor Annual Report," April 2001.

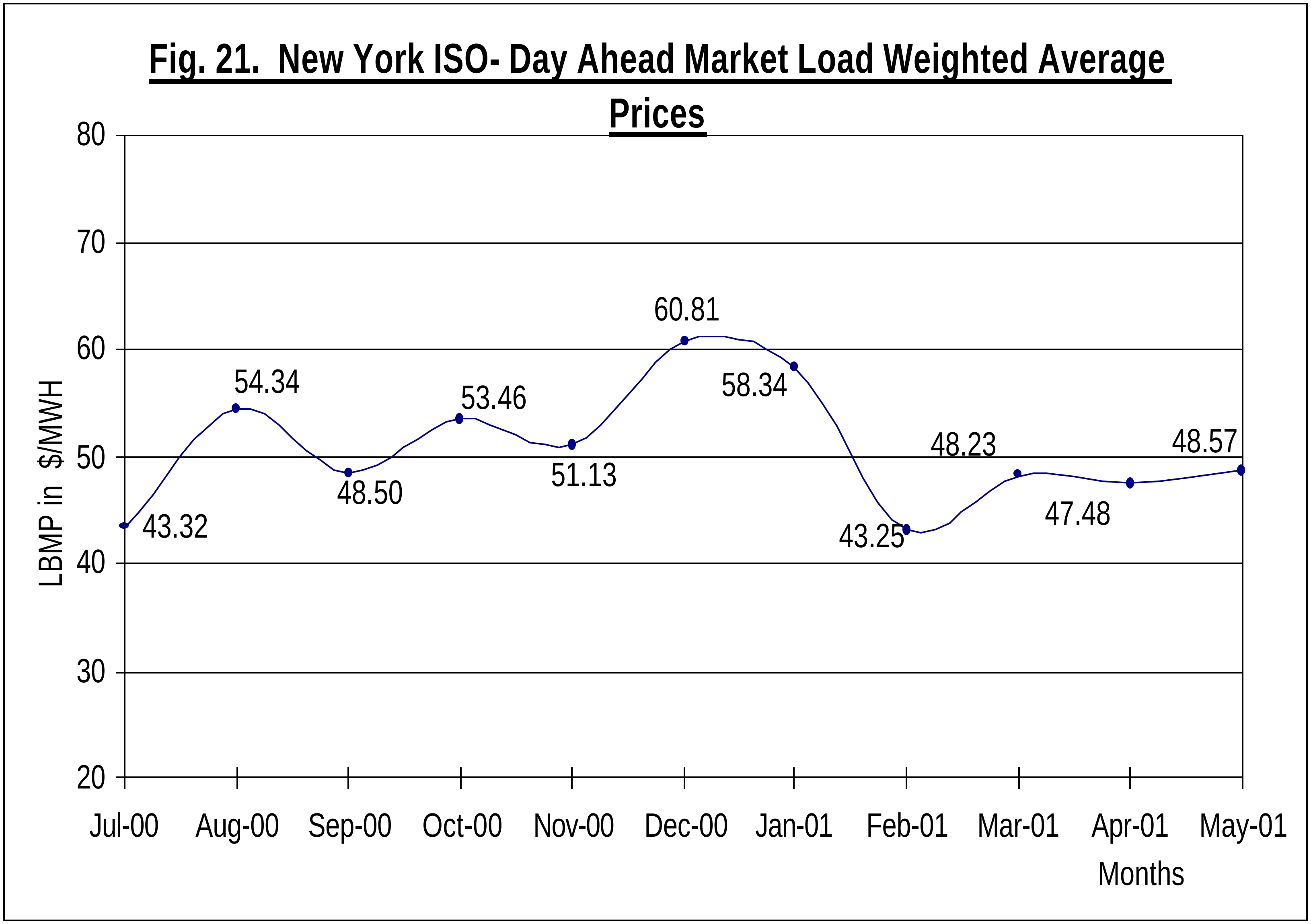


Fig. 21. New York ISO- Day Ahead Market Load Weighted Average Prices
LBMP in $/MWH
80
70
60
50
40
30
20
43.32
54.34
48.50
53.46
51.13
60.81
58.34
43.25
48.23
47.48
48.57
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Months

NYISO prices, he found, were not “unreasonably high during 2000 given the dramatic increase in fuel prices over the year and large unit outages – prices during 2000 would have averaged very close to 1999 levels without these factors.”

He did warn that to ensure the competitiveness of the New York markets in the future, entry of new generation and investment in transmission must be facilitated. In particular:

- “The inability of investors to site significant amounts of new generation in the face of growing loads will make the markets increasingly vulnerable to large price fluctuations, even without strategic withholding by suppliers;
- “I have forecasted that summer electricity prices are likely to rise by close to 50 percent over the next four years if new generation is not built;
- “The lack of new construction will also increase the vulnerability of the market to abuses of market power as transmission constraints and tight supply cause withholding to have a larger effect on prices;
- “The process for quantifying and awarding new transmission rights to those investing in new transmission should be completed to provide improved incentives to upgrade the network and relieve congestion.”

He noted further that:

> Over the longer term, the failure of new generation and transmission investment to keep pace with load growth will increase the vulnerability of the market to more frequent price spikes, increase the market’s exposure to market power or other forms of strategic behavior, and increase the costs associated with any market design flaws. The NYISO showed that the continued load growth has caused reserve margins in the State to drop from more than 25 percent to approximately 16 percent. Additional reductions in reserve margins are projected in the absence of new generation. . . . [the NYISO] projects annual electricity cost increases of approximately 20 percent . . . if new generation is not available to meet the growing load in the State.

Also, withholding in the 10-minute non-synchronous reserve market during the spring of 2000 caused ancillary services costs to increase substantially during late January through March of 2000. He notes that the amount of “10-minute NSR capability offered decreased substantially, while much of the capability that was offered was bid at levels substantially higher than previous levels (and higher than reasonable variable, opportunity, or other marginal costs). One of the principal factors contributing to this issue was the fact that the 10-minute NSR capability is principally held by only three suppliers, resulting in a highly concentrated market."

A report by the staff of the New York Department of Public Service (DPS Staff) is perhaps more pointed in its market assessment.[24] DPS Staff:

> . . . found significant problems with the NYISO's day-ahead, hour-ahead, and real-time operations caused by software design problems; rules that do not work as intended; and gaming that occurs when market participants try to take advantage of the simultaneous existence of problems with software, rules, and procedures.

The DPS Staff report declares that the "NYISO's market monitoring approach is insufficient to adequately protect consumers." They point out that:

> NYISO has sufficient capability to correct prices in cases of extreme market power (greater than 200% price impacts). However, more *moderate* abuses of market power, which raise prices by 0-200%, are likely to go undetected and unmitigated. To date, the NYISO has never formally mitigated for market power when the price impact is in the 0-200% range and has mitigated three times for price impacts above the 200% increase level [emphasis added[25]].

Among other conclusions reached by the DPS Staff :

> **The NYISO's thresholds for mitigation are too high**. Under NYISO rules, "rapid mitigation" thresholds are triggered only when there is a tripling of price or a price increase that exceeds $100/MWh, resulting from a market participant's exercise of market power. This threshold is too lax because significant harm can result from price increases below this level. Staff recommends that the NYISO petition FERC for approval of lower thresholds for rapid mitigation to the lesser of a 100% increase or $50/MWh of

[24]State of New York, Department of Public Service, "Interim Pricing Report on New York State's Independent System Operator," Department of Public Service Pricing Team, December 2000.

[25]Up to a 200 percent increase in price sounds, to this reviewer, more than "moderate."

> generator bids (compared to the current lesser of 300% or $100/MWh) and either the lesser of $50/MWh or 50% or 25% increases, depending on the number of hours over which the impact is measured, for the impact on market prices (compared to the current lesser of 200% or $100/MWh, one-hour threshold level).
>
> **Consumers need protection from price spikes**. In New York, a few large generators drove clearing prices to unreasonable levels on a few days during the summer of 2000 when demand was high. This occurred during a cool summer in New York. The wholesale market is dangerously vulnerable to market power abuse during a normal or hotter than normal summer.

They recommend a cap on market clearing prices of $150/MWh. A generator's bid would be allowed to exceed the cap but not set the market-clearing price. This measure would operate in conjunction with the existing $1,000/MWh bid cap and the circuit breaker to ensure that consumers pay more reasonable prices. Also:

> **The NYISO needs to make much greater use of several key market power analysis.** The NYISO has made little use of analytical tools that compare bids to marginal costs, which is used by other ISOs. Similarly, performing simulations of the market by using an ISO's computer models is a powerful way to gauge the price impact of suspect behavior. The NYISO's MMP Unit has recently obtained its own version of the day-ahead market's computer model for use in performing simulations and is now beginning to use marginal cost in its analysis. Staff recommends that these activities be pursued vigorously.

Another conclusion reached in the staff report is that since suppliers that exercise market power do not face penalties, there is insufficient deterrent to prevent it. When market power is detected, the bids may be mitigated on a going-forward basis for up to six months.

Finally, the NYDPS staff notes that their market power analysis is still in progress, but "there is strong reason to suspect that there is the potential for millions of dollars in consumer harm."

FERC granted approval June 28, 2001 of the NYISO's "Automated Mitigation Procedure" (AMP). The NYISO notes that AMP is essentially the automation of existing NYISO market monitoring measures. According to the NYISO "AMP is designed to prevent market abuse during times when the system is subject to very high load, excessive generator outages or binding transmission constraints and where energy prices rise above $150/MWh." During these conditions, supplier bids in the day-ahead market will be automatically reviewed to determine if they are: 1) $100/MWh or 300 percent higher than the energy reference price; or 2) in the case of start-up cost bids, if they are 200 percent higher than the start-up cost reference.   In addition, economic withholding must also cause a price impact of $100/MWh or a 200 percent increase. Reference prices are computed based upon the lower of the mean or median of the previous 90 days of accepted bids and are adjusted for fuel price changes. In instances when the AMP determines that a unit is economically withholding in the day-ahead market, that unit's bid price would be mitigated to its reference price. Based upon a preliminary analysis by the NYISO, the AMP would have resulted in mitigation in less than one quarter of one percent of the hours during 2000 (0.25 percent).[26]

It appears that the DPS Staff's concern that the thresholds for mitigation are too high remains at issue.

Conclusion

Retail market performance was measured in Part I in terms of the number of offers being made to residential customers, the potential savings opportunities these offers present, the number of suppliers in the area, the type of offers being made, and the percent of customers that selected an alternative supplier, among other factors. Since these performance measures are highly dependant on prices in the wholesale market, retail market performance cannot be viewed in isolation, but should be considered alongside an analysis of wholesale market performance as well.

Higher wholesale prices alone, while perhaps causing a problem in retail markets, would not necessarily indicate a poorly functioning market. Rather, wholesale market

[26] New York Independent System Operator, "NYISO Applauds FERC Approval of Automated Mitigation Procedure ('AMP')," News Release, Guilderland, New York, June 29, 2001.

performance should be analyzed in terms of how closely actual prices have been tracking what would occur in a fully competitive market. Wholesale prices may increase because of higher input costs (such as from higher natural gas prices), a scarcity of supply capacity (from increased demand or loss of existing capacity for example), or because suppliers are able to raise and maintain the price above a competitive level. If the high prices are due to input costs or scarcity, then, over time as new capacity is added for example, it may correct itself and may not require any policy adjustments. If it is the suppliers' ability to exercise a degree of price control, however, then the problem is in the wholesale market and should not be blamed on the retail design alone.

The evidence suggests that wholesale markets are having problems with suppliers being able to control, at least to some significant degree, the market price. Moreover, the characteristics of electricity and its delivery system to customers suggests that the market power can be considerable and continue for a long time.

These characteristics include that (1) demand for electricity is very inelastic, (2) markets are very concentrated for most geographic regions, even for multi-state wholesale regions; and (3) supply from potential rival firms is also inelastic, that is, market entry from other firms difficult and is often limited from outside the area by transmission constraints.

Since growing demand in California was not matched with additional supply, there is little doubt that scarcity played a role in the California crisis. What would be expected is that the price would be driven up to the marginal cost of the highest cost marginal unit needed to satisfy demand–a higher marginal cost than would obtain than during times of relatively plentiful supply. However, it is clear that actual prices exceeded, often greatly exceeded, the expected higher marginal cost.

There is evidence that suggested that even before the summer of 2000, market power was significant in California, particularly during peak hours. Several analyses of the California market present evidence that there was substantial market power during the recent crisis–as seen in the analyses by the California ISO's Market Surveillance Committee and its Department of Market Analysis

For the PJM ISO region, one independent analysis found that market imperfections in the PJM spot energy and bilateral contracts markets were very significant. Considerably exceeding estimates made by PJM's own Market Monitoring Unit. Similar quantitative analysis have not been conducted of the New York and New England ISO regions. However, there is evidence that suggests suppliers in these markets may also have considerable market power based on supplier behavior.

For other regions of the county that do not have organized spot markets, access to thorough information, or lack the type of comprehensive analyses conducted of the four markets discussed here, it is much more difficult to determine how well markets are developing. Some limited price information may be available, through price indices and futures markets. However, these may not present a complete picture of market transactions or provide enough data for a reliable estimate of market power. Both economic theory and common sense suggests that a lack of reliable information may simply invite mischief and delay needed changes to reduce market power and improve the health of the market. To echo the New York DPS staff, there is the potential for millions of dollars, or billions of dollars as seen in California, in consumer harm.

Since an attempt is being made to develop competitive markets to replace decades of state and federal regulation, it is generally assumed that these markets will require both time to develop and frequent adjustments when problems are encountered. Therefore, it is unlikely that idealized, perfectly competitive markets would develop immediately. Since these markets began relatively recently, and the transition period continues for most areas, markets are likely still evolving. Over time, as new generating capacity across the country comes on line wholesale prices may moderate and retail markets may be able to get back on track. However, given the characteristics of electricity demand, supply, and the concentrated nature of power markets, supplier market power may be both significant and persist for years to come.

Appendix

Table A.1. Summary of residential offers by state - May & July 2001.

State and Dist. Company	Renew-able offers		Offers from various sources		Long Term Contracts		Offers below price-to-compare		Number of suppliers		Percent savings on lowest offer	
	May	July	May	July	May	July	May	July	May	July	May	July
Arizona												
< Arizona Public Service	0	0	0	0	0	0	0	0	0	0	-	-
< Tucson Electric Power	0	0	0	0	0	0	0	0	0	0	-	-
California												
< Pacific Gas & Electric	1	1	0	0	0	0	0	1	1	1	-	2.7
< San Diego Gas & Electric	0	0	0	0	0	0	0	0	0	0	-	-
< Southern California Edison	1	1	0	0	0	0	1	1	1	1	2.5	2.5
Connecticut												
< Connecticut Light & Power	3	2	3	2	2	1	3	1	5	4	5.0*	2.3
< United Illuminating	2	1	1	0	0	0	1	0	3	1	5.0*	-
District of Columbia												
< Potomac Electric Power Co. (PEPCO)	1	0	1	0	0	0	1	0	2	0	4.9*	-
Delaware												
< Conectiv Power	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Delaware Electric Coop	1	0	1	0	0	0	1	0	2	0	5.0*	-

State and Dist. Company	Renew-able offers		Offers from various sources		Long Term Contracts		Offers below price-to-compare		Number of suppliers		Percent savings on lowest offer	
	May	July	May	July	May	July	May	July	May	July	May	July
Maine												
< Central Maine Power Co.	3	2	1	0	2	2	1	0	3	2	5.0*	-
< Bangor Hydro Elect Co.	1	0	2	1	1	2	2	1	3	1	5.0*	0.6
< Maine Public Service Co.	2	1	2	1	2	0	2	1	3	2	5.0*	0.2
Maryland												
< Allegheny Power	-	0	-	0	-	0	-	0	-	0	-	-
< Baltimore Gas & Energy	0	0	0	0	0	0	0	0	0	0	-	-
< Delmarva Power & Light / Conectiv	-	0	-	0	-	0	-	0	-	0	-	-
< Potomac Electric Power Co. (PEPCO)	-	0	-	1	-	1	-	1	-	1	-	3.0#
Massachusetts												
< Commonwealth Electric Co.	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Cambridge Electric Co.	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Western Mass Electric	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Boston Edison Co.	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Fitchburg Gas & Electric Light Co.	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Massachusetts Electric Co.	1	0	1	0	0	0	1	0	2	0	5.0*	-

State and Dist. Company	Renew-able offers		Offers from various sources		Long Term Contracts		Offers below price-to-compare		Number of suppliers		Percent savings on lowest offer	
	May	July	May	July	May	July	May	July	May	July	May	July
Montana												
< Montana Power Co.	0	0	0	0	0	0	0	0	0	0	-	-
New Jersey												
< GPU/Jersey Central Power & Light Co.	3	1	1	0	0	0	1	0	3	1	5.0*	-
< Atlantic City Energy Co./Conectiv	3	1	1	0	0	0	3	1	3	1	11.4	3.8
< Public Service Electric & Gas Co.	3	1	2	1	1	1	1	0	4	2	4.8*	-
New York												
< Central Hudson Gas & Electric Corp.	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Consolidated Edison Co. of New York	1	0	4	0	3	2	1	0	5	0	5.0*	-
< New York State Electric & Gas Corp.	1	0	1	2	0	0	1	0	2	2	5.0*	-
< Niagara Mohawk Power Corp.	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Orange & Rockland Utilities	1	0	1	0	0	0	1	0	2	0	5.0*	-
< Rochester Gas & Electric Corp.	1	0	2	0	0	0	2	0	3	0	8.7	-

State and Dist. Company	Renew-able offers		Offers from various sources		Long Term Contracts		Offers below price-to-compare		Number of suppliers		Percent savings on lowest offer	
	May	July	May	July	May	July	May	July	May	July	May	July
Ohio												
< AEP/Columbus Southern Power Co.	1	0	2	1	1	1	1	0	3	1	5.0*	-
< AEP/Ohio Power Co.	1	0	1	0	0	0	0	0	2	0	5.1*	-
< Cincinnati Gas & Electric Co.	1	0	2	1	1	1	1	0	3	1	5.0*	-
< Dayton Power & Light	1	0	1	0	0	0	1	0	2	0	5.0*	-
< First Energy/Illuminating Co.	0	0	0	0	0	0	0	0	0	0	-	-
< First Energy/Ohio Edison Co.	1	0	2	1	1	1	1	0	3	1	5.0*	-
< First Energy/Toledo Edison Co.	1	0	2	1	1	1	1	0	3	1	5.0*	-
Pennsylvania												
< Allegheny Power	4	2	1	0	0	0	1	0	3	2	5.0*	-
< Duquesne Light Co.	4	2	2	1	1	1	1	0	4	3	5.0*	-
< GPU/Metropolitan Edison Co.	4	2	1	0	0	0	1	0	3	2	5.0*	-
< PECO	7	5	4	2	5	3	2	2	9	7	5.0*	2.6
< GPU/Pennsylvania Electric Co.	4	2	1	0	0	0	2	0	3	2	5.1*	-

State and Dist. Company	Renew-able offers		Offers from various sources		Long Term Contracts		Offers below price-to-compare		Number of suppliers		Percent savings on lowest offer	
	May	July	May	July	May	July	May	July	May	July	May	July
Pennsylvania *(continued)*												
< Pennsylvania Power Co.	4	2	2	1	1	1	2	0	4	3	5.0*	-
< Pennsylvania Power & Light	4	2	1	0	0	0	1	0	3	2	5.0*	-
< UGI Utilities	4	2	1	0	0	0	1	0	3	2	5.0*	-
Rhode Island												
< Narragansett Electric Power Co.	1	0	1	0	0	0	1	0	2	0	5.0*	-
Totals	79	30	56	16	22	18	48	9	113	46		

* Offer by ServiSense, that bundles electric service billing with one or more other utility service(s).
Source: Compiled from Wattage Monitor (http://www.wattagemonitor.com).
[#] State of Maryland Office of the Attorney General
Source: Compiled from Wattage Monitor (http://www.wattagemonitor.com) other state sources.

Biography

Kenneth Rose, Ph.D. is a Senior Institute Economist in the Electric and Gas Research Division of The National Regulatory Research Institute at Ohio State University. Dr. Rose has been working on energy and regulatory issues for more than seventeen years. Dr. Rose has testified or presented at many state legislative and public utility commission hearings, proceedings, conferences, and workshops on electric industry restructuring and has testified before several committees of the U.S. House of Representatives on regulatory matters. Since joining the Institute in 1989, he has worked primarily on studies concerning the electric industry and has directed or contributed to many reports, papers, articles, and books. Topics include Clean Air Act implementation, environmental externalities of electricity production, competitive bidding for power supply, regulatory treatment of uneconomic costs, market power, and other industry restructuring issues. Dr. Rose is a frequent presenter at conferences, workshops, and other instructional venues. Prior to coming to the NRRI, Dr. Rose worked on many energy related issues at Argonne National Laboratory. Dr. Rose received his B.S., M.A., and Ph.D. in Economics from the University of Illinois at Chicago.