

# **2004 Performance Review of Electric Power Markets**

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**Review Conducted for the Virginia State Corporation Commission\***

August 25, 2004

\*This report was conducted under contract with the Virginia State Corporation Commission as Part I (of three parts) of the Commission's annual report to the Virginia General Assembly on the advancement of a competitive retail electricity market in the Commonwealth of Virginia. The views expressed here are those of the author and do not necessarily reflect the views or opinions of the Virginia State Corporation Commission.

## EXECUTIVE SUMMARY

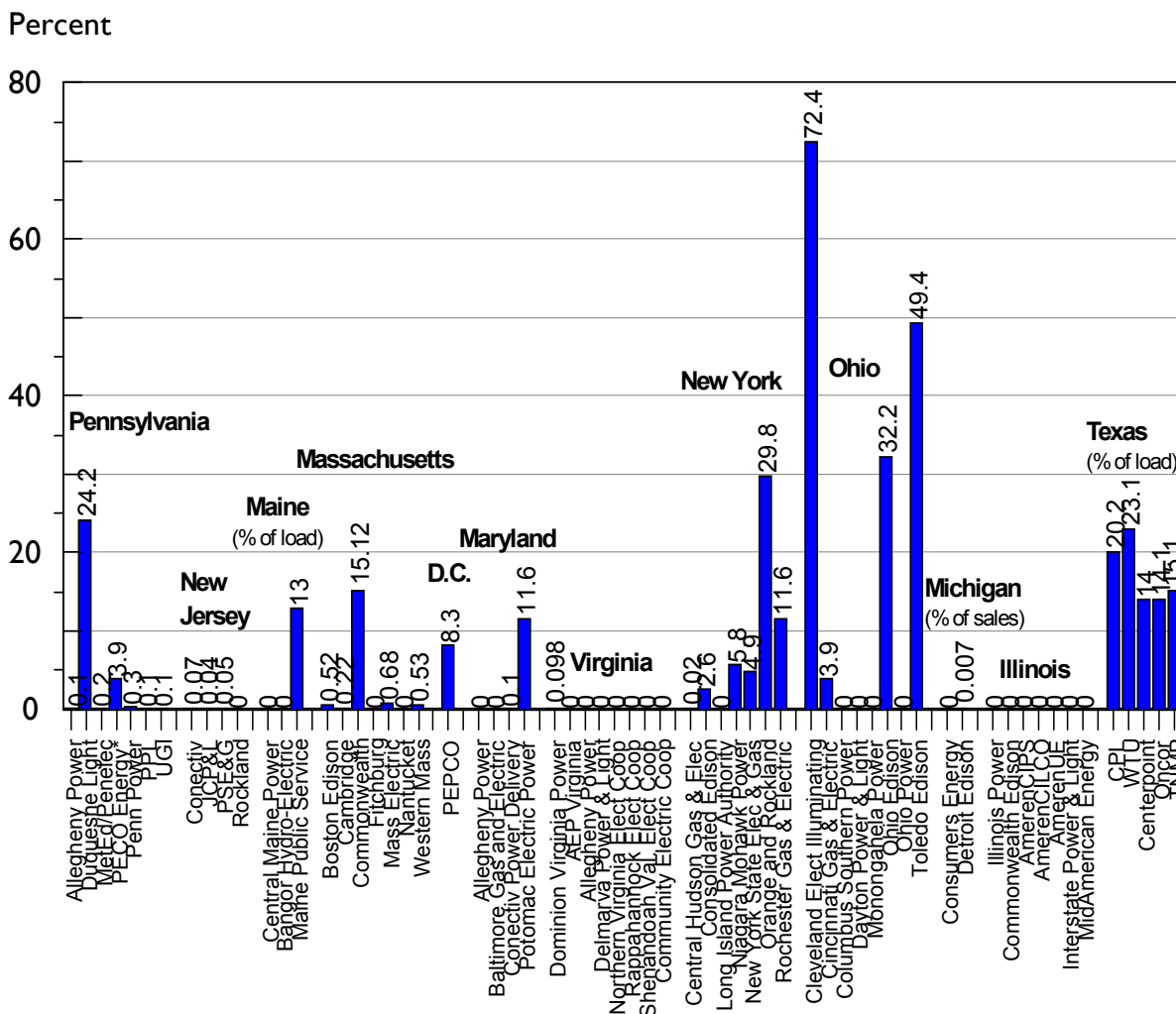
Since the price run-ups in California and the West beginning in mid-2000 and into 2001, the electric supply industry has not been able to return to a relative stable or calm period of time. The industry's problems continued after the western power crisis with Enron's disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, the continuing "credit crunch," and, the major event of 2003, the most extensive blackout in North American history.

In the face of this turmoil, most states have decided to either discontinue their efforts to implement retail access or have stopped considering adopting it altogether. The overall picture of which states have adopted retail access has not changed substantially in the last few years. Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger customers only; Nevada, that modified its original law to limit access to just larger customers and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation, Arkansas and New Mexico have repealed their laws, California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana, has also been dealing with the severe aftermath of the western power crisis, has extended the transition period to retail access for smaller customers. They implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 was postponed to 2027. While there are some large retail customers in western state retail markets active in the market (in California, Montana, and Oregon), in general, these retail markets have not yet fully recovered from the western power crisis.

Twenty six states are no longer considering restructuring at this time and none of these states appear to be near passage of restructuring legislation or working in any meaningful way toward passage at this time. In fact, no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. These states that did not pass legislation but were in the process of considering it either gradually lessened their efforts to allow time to consider what was occurring in the west or they abruptly stopped any activity that was ongoing at the time. A total of 32 states have repealed, delayed, suspended or are now no longer considering retail access.

For the 16 states and D.C. that have continued with retail access, many retail markets have remained relatively inactive, particularly for smaller residential customers. Figure ES.1 shows the percent of residential customers that are supplied by an alternative supplier to their local utility in 11 states and D.C. Of the 63 distribution

companies represented in the figure, 43 or over two-thirds of the companies, had less than one percent of the customers choosing an alternative, most (27) were zero. Only seven have greater than 20 percent of the residential customers receiving power from alternative suppliers. Three of those seven distribution companies are in Ohio where nearly 95 percent of the residential switching in the state has been through the state's aggregation program. Two of the remaining four distribution companies were in relatively higher priced states, Pennsylvania and New York (although not the highest priced distribution companies in the state, each were the second highest priced distribution company in their state) and the two Texas distribution companies had the highest "price-to-beat" (the price-to-compare for residential customers) in the state.

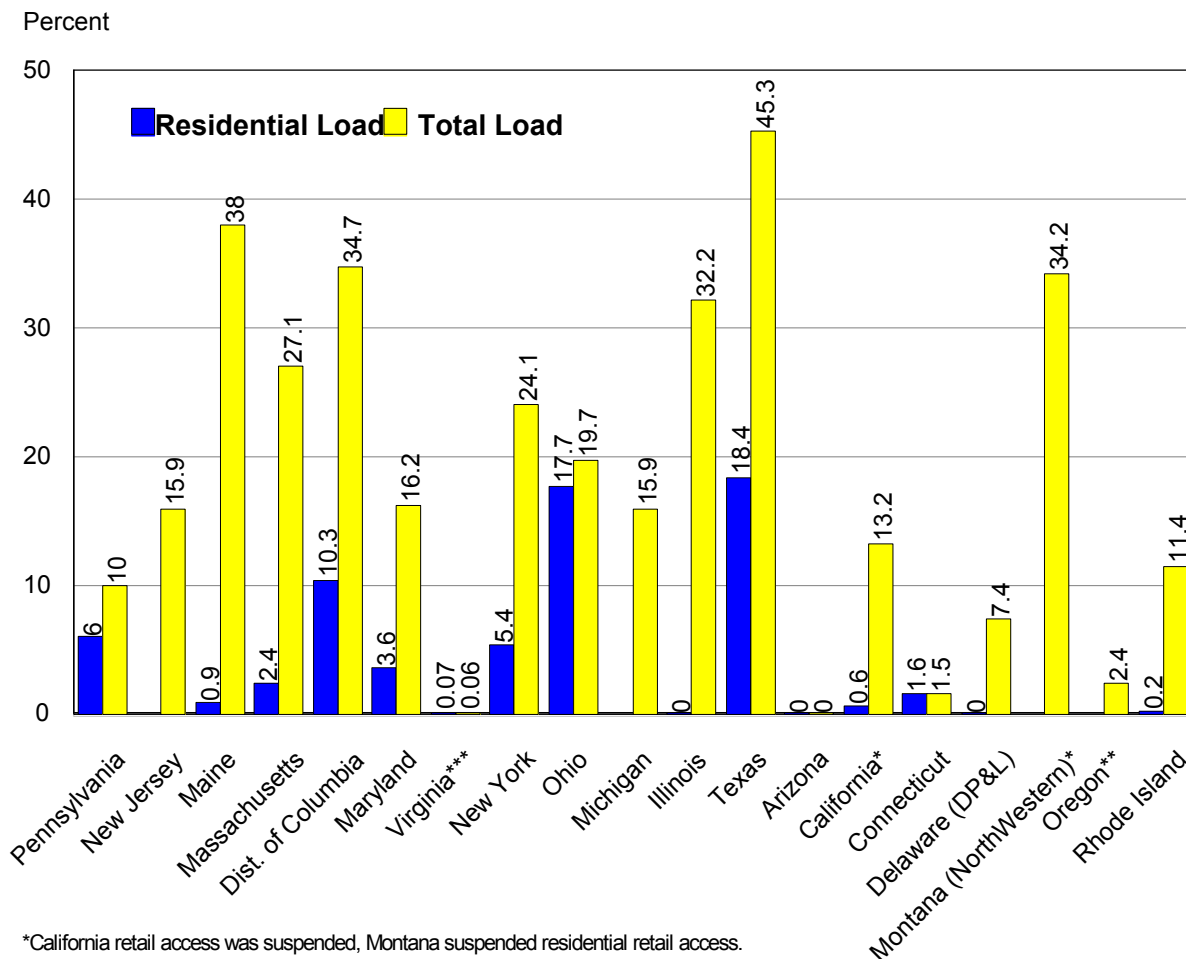


\*PECO Energy percentage excludes assigned customers.

Data Sources: Various state agencies; Texas data from KEMA, Inc., "Retail Energy Foresight," June/July 2004.

**Figure ES.1.** Percent of residential customers switching to alternative suppliers, by distribution company.

Four of the five states with retail access for all customer groups that were not shown in Figure ES.1 are represented in Figure ES.2.<sup>1</sup> Figure ES.2 summarizes residential customer load and the state total customer load that have switched to an alternative supplier for 19 states and D.C. This figure shows the significant difference between residential customer migration to competitive suppliers and total state load



\*California retail access was suspended, Montana suspended residential retail access.

\*\*Oregon has retail access for large customers only.

\*\*\*Virginia percentages are percent of customers, all others are percent of load.

Data Sources: Various state agencies and KEMA, Inc., "Retail Energy Foresight," June/July 2004.

**Figure ES.2.** Summary of residential and total state customer load served by alternative suppliers.

<sup>1</sup>The two states not shown in either figures are New Hampshire, that reported a relatively low level of activity last year, and Nevada, which has retail access for large customers only, and (from state media accounts) had no customer switching from incumbent suppliers.

migration. This difference is due to the relatively greater market activity of the larger customer groups. While there are seven states where there are more than 20 percent of the total state load now being served by competitive suppliers, no state has reached that point for residential load. Only two states and D.C. have surpassed 10 percent of residential load, one of these states is Ohio, which again is mainly attributable to the state's aggregation program. Five of the seven states (including D.C.) where total load was greater than 20 percent were in relatively higher priced regions. The two exceptions were Texas, where again a substantial portion of the retail activity has been in the higher priced distribution companies of the state, and Montana, which began restructuring as one of the lowest-priced states in the country and where retail access is limited to only large customers. However, due to the western power crisis of 2000 and 2001, those customers that entered the power market paid considerably higher prices than they had before restructuring began.

Several states are now also using bidding or auctions to procure power supply for their non-choosing customers. The Maine Public Utilities Commission has conducted four rounds of competitive bidding since March 2000. Currently, all customers not receiving power from a competitive supplier are on competitively-determined standard offer price, this includes nearly all residential customers in the state. New Jersey has had three auction rounds of an Internet-based, simultaneous, multi-round, and descending clock auction. The "Basic Generation Service" load is auctioned simultaneously for all four New Jersey electric utilities. Maryland had its first round of competitive bidding for two distribution companies in 2004.

Wholesale markets and the transmission organizations that these markets often operate in, are continuing to evolve. The most extensive of these transmission regions are the three that operate in the northeastern U.S. in New England, New York, and the mid-Atlantic states. These areas have centralized spot power markets and independent transmission operation. Other parts of the country are developing similar structures, but did not begin with the same level of integration that the northeast regions began with and are still developing.

A common theme that most wholesale markets shared in the last two years is the substantial impact that the price of natural gas now has on power prices. In particular, the natural gas price spikes that occurred across the country in early 2003 and in the northeast region of the country in early 2004, led to corresponding power price spikes in these regions. Even when natural gas is not the most commonly used fuel to generate power in the region, because it is often the marginal fuel used and because many power contracts have the price for power pegged to natural gas prices, natural gas and power prices now generally move in tandem.

The most prominent industry event of 2003 was the August 14th blackout. This was the most extensive blackout in North American history, affecting an area of 50 million people and 61,800 MW of electric load in all or part of eight states and one

Canadian province. Estimates of the total cost in the U.S. range between \$4 billion and \$10 billion. Power was not restored for four days in some of the states and parts of Ontario had rolling blackouts for more than a week after. It is likely that this event will have a far reaching impact on the industry for the foreseeable future. A joint U.S. and Canadian Task Force was appointed to examine the cause of the blackout and make recommendations for improvements to avoid a recurrence. The Task Force's first recommendation was: "Make reliability standards mandatory and enforceable, with penalties for noncompliance." They state that "the single most important" recommendation they make is that "the U.S. Congress should enact the reliability provisions in H.R. 6 and S. 2095 to make compliance with reliability standards mandatory and enforceable." To date, this recommendation has not been met and is unlikely to happen until sometime during 2005 at the earliest.

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# **SECTION I**

## **Overview of Electric Restructuring Activities and Issues in the U.S.**

### **Introduction**

Since the price run-ups in California and the West beginning in mid-2000 and into 2001, the electric supply industry has not been able to return to a relative stable or calm period of time. The industry's problems continued with Enron's disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, the continuing "credit crunch," and, the major event of 2003, the most extensive blackout in North American history.

In the face of this turmoil, most states have decided to either discontinue their efforts to implement retail access or have stopped considering adopting it altogether. For the 16 states and D.C. that have continued with retail access, many retail markets have remained relatively inactive, particularly for smaller residential customers. About two-thirds of the distribution companies had no or less than one percent residential customer migration from utility service. However, for some states, market activity for larger customers has been relatively stronger. Nine states had at least one distribution company with at least one non-residential customer category with 20 percent or greater of those customers buying power from an alternative supplier. Generally, these are in relatively higher priced distribution companies' territories. Several states are now also using bidding or auctions to procure power supply for their non-choosing customers. There is considerable variation, however, across states and even within a particular state on how retail markets have performed.

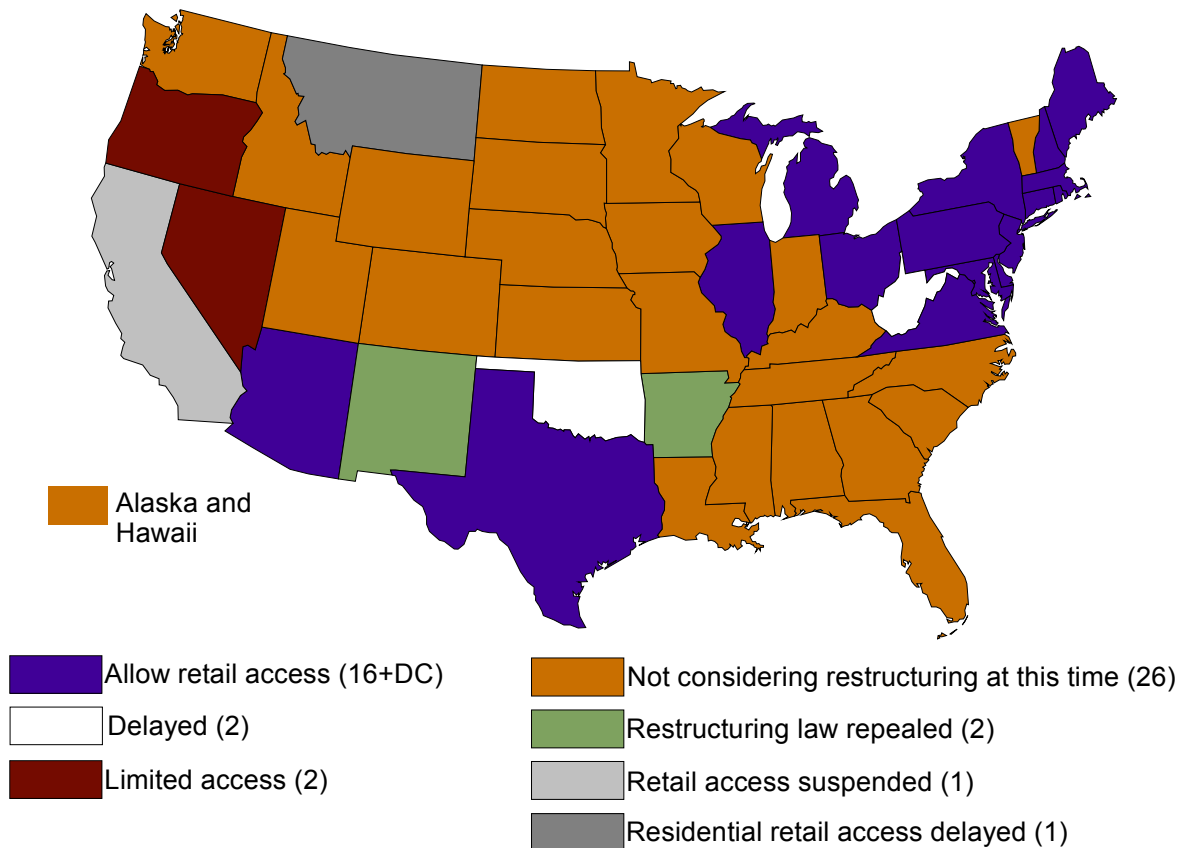
Wholesale markets and the transmission organizations that these markets often operate in, are continuing to evolve. The most extensive of these transmission regions are the three that operate in the northeastern U.S. in New England, New York, and the mid-Atlantic states. These areas have centralized spot power markets and independent transmission operation. Other parts of the country are developing similar structures, but

did not begin with the same level of integration that the northeast regions began with and are still developing.

This Performance Review covers retail and wholesale market developments by region. The remainder of this section first provides an overview of state restructuring activities. Next, some recent important industry developments are summarized, including the continuing “credit crunch,” generation capacity additions, the impact of higher natural gas prices, generation assets sales, the August 2003 blackout, transmission system investment, and an overview of regional transmission organization developments. This section then concludes with an explanation of how market performance is measured in both wholesale and retail markets. The next seven sections examine different regions of the country in terms of price and other factors to provide an indication on how the wholesale markets are performing in the regions. The regions examined here are the Mid-Atlantic, New England, New York, Midwest, Southeast, Texas, and the West. The state retail markets are investigated within each of the regional sections.

### **Summary of State Electric Restructuring Activities**

Figure I.1 summarizes the current status of state retail access. Overall, the picture has not changed substantially in the last few years. Sixteen states and D.C. have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger customers only; Nevada, that modified its original law to limit access to just larger customers and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation, Arkansas and New Mexico have repealed their laws, California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Montana, has also been dealing with the severe aftermath of the western power crisis, has extended the transition period to retail access



**Figure I.1.** Status of state retail access.

for smaller customers. They implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 was postponed to 2027. While there are some large retail customers in western state retail markets active in the market (in California, Montana, and Oregon), in general, these retail markets have not yet fully recovered from the western power crisis.

Twenty six states are no longer considering restructuring at this time and none of these states appear to be near passage of restructuring legislation or working in any meaningful way toward passage at this time. In fact, no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. These states that did not pass legislation but were in the process of considering it either gradually lessened their efforts to allow time to consider

what was occurring in the west or they abruptly stopped any activity that was ongoing at the time. A total of 32 states have repealed, delayed, suspended or are now no longer considering retail access.

### **Industry “Credit Crunch”**

As documented in the last two year’s Performance Reviews, the “credit crunch” has severely impacted the ability of power suppliers, especially competitive merchant suppliers, to raise capital and has forced companies to cut back on their energy trading operations, new plant investments, and fostered a “back-to-basics” strategies for many companies. Standard & Poor’s (S&P) noted that the constrained access to capital was due to several investor concerns, including the accounting practices and disclosure, federal and state investigations, and investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities.<sup>2</sup> This ratings trend for the investor-owned utility industry (which include electric, gas, pipeline, and water companies) has continued since early 2000, and accelerated in the first quarter of 2003. S&P noted that there were “an unprecedented 50 downgrades among holding companies and operating subsidiaries, compared with just three upgrades during the first three months of 2003.”

In early 2004, S&P noted a “reduced pace” of credit rating downgrades when compared to the previous two years. The number of rating changes on holding companies and operating subsidiaries dropped to 17 downgrades and two upgrades in the first quarter of 2004, from the 50 downgrades and three upgrades in the first quarter of 2003.<sup>3</sup> However, they note that the distribution of outlooks did not change much from 2003. The percentage of negative outlooks for utility sector companies increased slightly to 34 percent on March 31, 2004 from 31 percent in the first quarter of 2003.

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<sup>2</sup>Standard & Poor’s, “Downside Rating Trend Continues For U.S. Utilities in First Quarter,” April 24, 2003.

<sup>3</sup>Standard & Poor’s, “Industry Report Card: U.S. Electric/Water/Gas,” April 30, 2004.

S&P put positive outlooks at only about 2 percent. Echoing previous reports, S&P again made a distinction between companies that are primarily still vertically structured:

Standard & Poor's expects that most companies whose core focus is on providing electricity and gas service will maintain financial profiles that warrant--at a minimum--investment-grade ratings. Prospectively, Standard & Poor's expects the traditional, nondiversified, and regulated U.S. investor-owned electric and gas industry to remain relatively stable, with little of the downward pressure experienced elsewhere in the energy industry.<sup>4</sup>

However, for those companies that are substantially involved in competitive activities:

The outlook for the competitive segment of the industry continues to be largely negative. Merchant power generators are still facing many of the same issues that caused their widespread credit deterioration in 2002 and 2003. With natural gas prices remaining high and capacity overbuild expected to continue for the next several years, market conditions are not dramatically improving.<sup>5</sup>

S&P has noted that some companies are decreasing or discontinuing their investments in unregulated businesses, including merchant generation, energy trading, and international investments--strategies that were intended to help them deal with competitive markets and to enhance shareholder value. Another trend S&P has noted is the number of utility and power companies rated 'BBB' (companies considered to have an "adequate capacity to meet its financial commitments") and below has increased, while the number of firms rated 'A' and above has decreased ('A' rating is given to companies with a "strong capacity to meet its financial commitments"). However, they believe that credit ratings will stabilize at current levels.<sup>6</sup> In 2003, they noted that the large number of downgrades had caused the average rating for the U.S. power sector as a whole to slip into the mid-'BBB' area. They do not expect the industry

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<sup>4</sup>Standard & Poor's, April 30, 2004, p. 2.

<sup>5</sup>Standard & Poor's, April 30, 2004, p. 2.

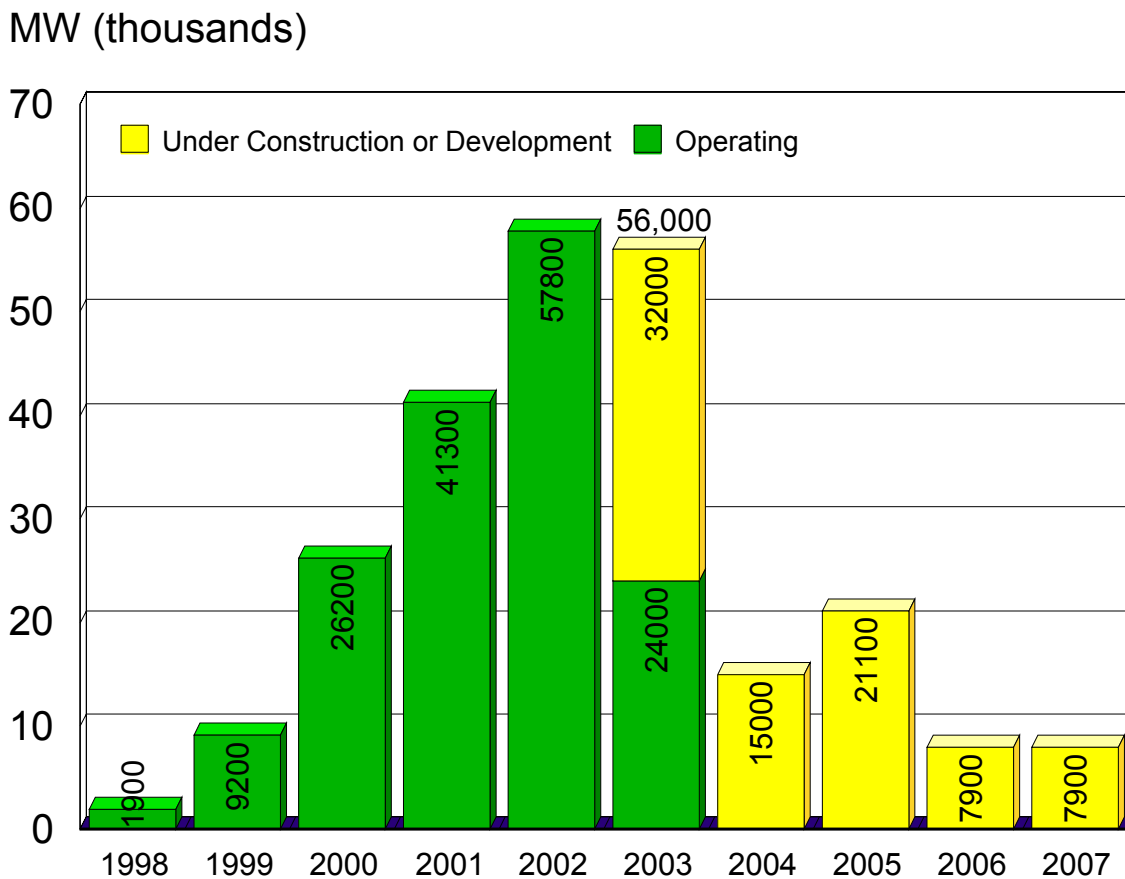
<sup>6</sup>Standard & Poor's, "S&P Says U.S. Utilities and Power Industry Ratings Stabilizing," June 2, 2004.



to fall below that level and state that “companies that continue to emphasize a vertically integrated structure should hang onto an ‘A-’ average”.<sup>7</sup>

### Natural Gas Capacity and Natural Gas Prices

The continuing credit crunch, combined with weak market conditions in many regions for merchant power suppliers, has led to a significant cut back in investment in future generating capacity. As Figure I.2 shows, after a period of several years of the



**Figure I.2.** Gas-fired turbine-based capacity additions in operation, 1998 to 2003, and capacity in development, 2003 to 2007.

Data Source: NERC Reliability Assessment 2003–2012, December 2003 (Energy Ventures Analysis, Inc. data).

<sup>7</sup>Standard & Poor's, "Downside Rating Trend Continues," April 24, 2003, p. 3.

largest capacity expansion in the industry in over half a century, the amount of capacity in the development stage or under construction has dropped substantially. In 2002, 57,800 MW of gas-fired capacity was added with more than 50,000 MW expected again for 2003.<sup>8</sup> This followed the 1999 through 2001 period when a total of 76,700 MW was added. The 1999 through 2002 additions are almost 15 percent of the industry's total net summer generating capacity in 2002. This compares with the period 1986 through 1998 when a total of 53,900 MW of gas-fired capacity was added for the entire period.<sup>9</sup> Coal capacity additions, in contrast, is expected to be only 12,800 MW between 2000 to 2009.<sup>10</sup> No new plants entered construction during the first quarter of 2003.

With these additions, natural gas-capable capacity accounted for about 37 percent of the total U.S. net summer capacity in 2002.<sup>11</sup> The increasing importance of natural gas as a fuel source for power generation added to the fact that natural gas is the marginal fuel in most regions of the country, have combined to make natural gas prices a critical determinate in power prices. It is now common practice to index power transaction prices to a natural gas price index. Spot market prices for electricity, not surprisingly, respond almost immediately to changes in the price for natural gas. As will be seen in the regional section of this report, markets around the country (PJM, New England, New York, Midwest, Texas, and Western markets), were significantly impacted in early 2003 and again in early 2004 by the spikes in natural gas prices.

Figure I.3 graphs four natural gas price indices for 2003 through May 2004. For illustration purposes, Figure I.4 provides a comparison of the New York natural gas price index and power prices in the New York wholesale market (Zone J is for the New

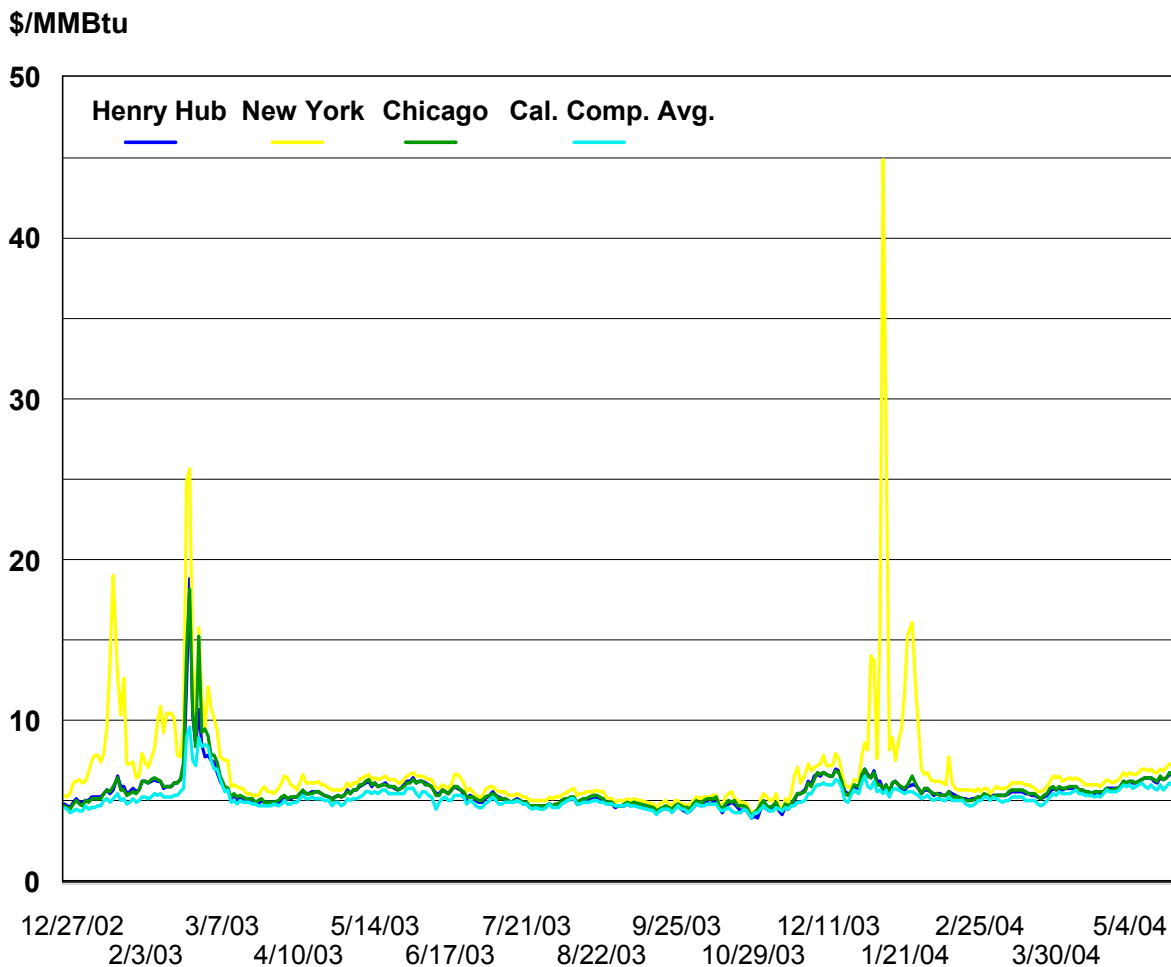
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<sup>8</sup>NERC Reliability Assessment 2003-2012, December 2003. Energy Ventures Analysis, Inc. data.

<sup>9</sup>Electric Power Research Institute, "Energy Market and Generation Response," June 2003.

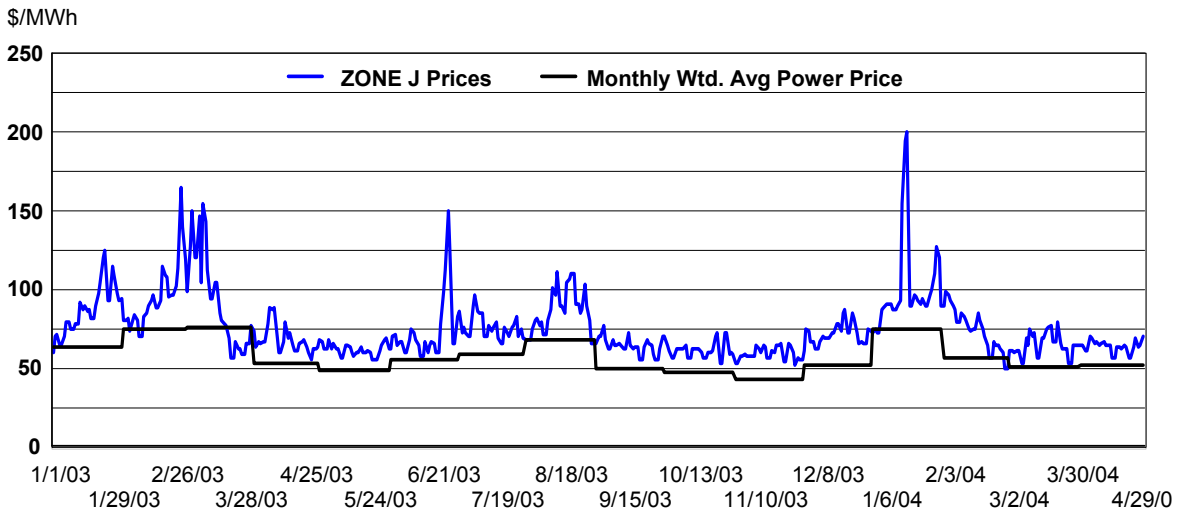
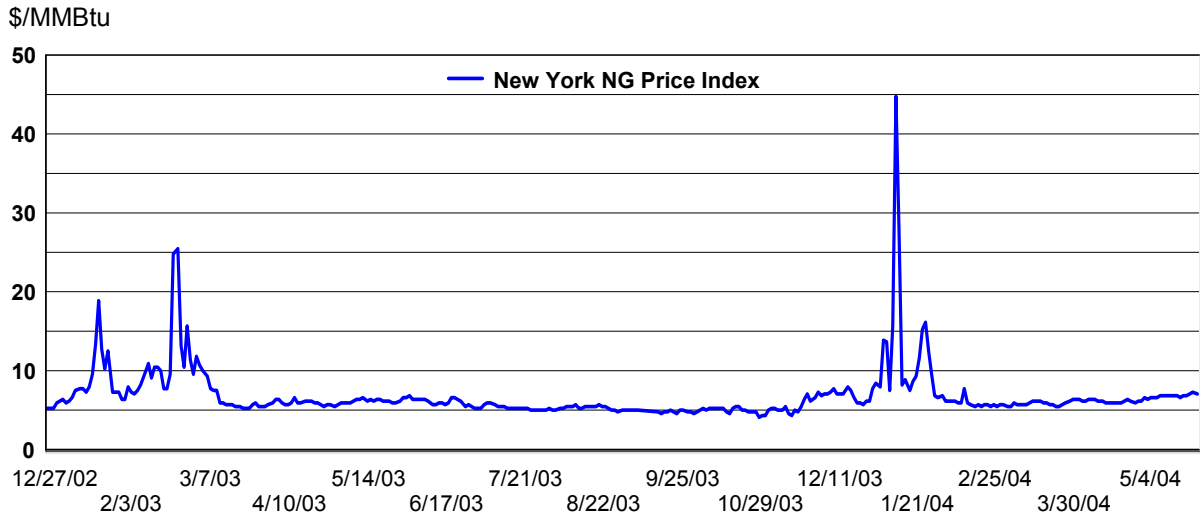
<sup>10</sup>EPRI, June 2003, p. 2.

<sup>11</sup>Based on figures from the U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 2002*, December 2003. Natural gas-only capacity is about 19 percent of the total U.S. net summer capacity for 2002 and "dual fired" capacity is about 18 percent. Since most dual fired plants consume natural gas most of the time (and use oil as a back-up), the total natural gas capable capacity is the sum of the natural gas-only capacity and dual fired capacity, for a total natural gas capable capacity of 37 percent of the total U.S. net summer capacity for 2002.



**Figure I.3.** Daily natural gas price index, January 2003 through May 2004. Data Source: U.S. Department of Energy, Energy Information Administration, “Natural Gas Weekly Update,” data from NGI’s Daily Gas Price Index.

York City area, the weighted average monthly price is from the New York ISO). This pattern of a close correlation between power market prices and natural gas prices is repeated in nearly every power market, which are shown in the regional sections. If natural gas prices continue to remain at current levels and continue to surge higher on occasion, this will continue to have a significant impact on both short- and long-term power prices across the country.



**Figure I.4.** New York natural gas price index and ISO daily and monthly weighted-average power prices.

Data Sources: DOE/EIA, Platts Megawatt Daily, and New York ISO.

## Recent Generation Assets Sales

Relatively little industry attention has been given to the considerable recent transfer of ownership of power plants and other power industry assets in the U.S., and the fact that many of the buyers of these assets have been financial or investor groups. What is noteworthy is that these “financial sponsors” have not been significant owners or holders of power industry assets in any significant amount in the past. A report by Cambridge Energy Research Associates (CERA report)<sup>12</sup> examined 93 power sector asset transfers that occurred between July 2002 and July 2004. This included transactions for power plant purchases, the acquisition of transmission assets, and the pending purchases of two regulated utilities. Over 80 of these asset transfers were for about 275 operating power plants with a net installed capacity of more than 50,000 MW.<sup>13</sup> Nearly 65 percent, or 30,973 MW of the 50,000 MW were acquired by “financial sponsors.” These financial sponsors are directly investing in the power industry and include private equity fund managers, leveraged buyout firms, commercial banks, hedge funds, and commodity traders. The CERA report suggests that these investors intend to be relatively short-term owners, since they typically hold assets for two to seven years and are seeking relatively high returns. The other purchasers of these assets were: electric utilities that purchased 11,183 MW, independent generators that purchased 1,749 MW, public power entities that purchased 3,148 MW, Canadian companies that acquired 1,683 MW, and 1,234 MW that were purchased by other entities.

At this time, the total share of the industry’s capacity transferred to financial sponsors is relatively small (about 3.4 percent of the total 2002 net summer generating capacity in the U.S.), however, if this trend continues, it could significantly impact the industry’s current structure in an unprecedented way.

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<sup>12</sup>Paul Parshley, “Barriers to Exit: Can Financial Sponsors Turn Their New Megawatts into Megabucks?,” Cambridge Energy Research Associates, Inc., July 2004.

<sup>13</sup>While this is only about 5.5 percent of the total 2002 total net summer generating capacity in the country, the fact that the 50,000 MW of capacity changed ownership in only a two year period and that it occurred during a relatively turbulent time in the industry’s history, makes it notable.

The sellers of these assets vary and are an interesting part of the industry's recent history. These sellers included merchant or independent generating company "fallen angels," that sold about 11,500 MW or 23 percent of the capacity sold during this period.<sup>14</sup> These companies expanded rapidly during the boom years that began in the late 1990s (as shown in Figure I.2 above for new capacity development), but when market conditions changed (such as the much higher natural gas prices), their highly leveraged positions were no longer sustainable and caused them to liquidate assets to raise cash and pay down debt. Similarly, power traders<sup>15</sup> also sold assets they accumulated when they exited the power trading business, selling about 5,700 MW of generating capacity or about 11 percent of the total capacity sold. Also two regulated utilities, Portland General Electric Company (an Enron affiliate) and Illinois Power Company (a Dynegy affiliate) are currently in the process of being sold from this power trading group.

The largest share of the capacity sold was by electric utilities, which sold almost 18,000 MW or about 35 percent of this plant capacity sold. These are traditional electric utilities that are selling non-core assets in a "back-to-basics" strategy to improve credit quality (as discussed above) and financial condition. This includes Allegheny Energy and TECO Energy that are selling assets to restore their financial health after "severe liquidity crises" and other utilities that have not suffered that same type of financial crises, such as AEP, Duke Energy, and Exelon, but are selling non-core assets in their return to more traditional utility business concerns. In addition, about 5,500 MW of generating assets were sold by non-U.S. companies and about 4,700 MW of capacity was sold as "regulatory requirements" – the bulk of this second category were AEP's sales in Texas of their fossil-based units (3,800 MW) and their share of a nuclear plant (630 MW).

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<sup>14</sup>CERA included in this group AES Corporation, Calpine, Cogentrix, Mirant, NRG Energy, and Reliant Resources (now Reliant Energy).

<sup>15</sup>Included here are Enron, El Paso Corporation, Williams Companies, Dynegy, and Aquila.

## The August 14, 2003 Blackout

The most prominent industry event of 2003 was the blackout that occurred on August 14<sup>th</sup>. This was the most extensive blackout in North American history, affecting an area of 50 million people and 61,800 MW of electric load in all or part of eight states and one Canadian province.<sup>16</sup> Estimates of the total cost in the U.S. range between \$4 billion and \$10 billion. Power was not restored for four days in some of the states and parts of Ontario had rolling blackouts for more than a week after.<sup>17</sup> The widespread impact and duration of the outage clearly captured the attention of the general public, politicians, federal and state regulators, electric utilities and competitive suppliers, trade groups and associations, and others in the power industry. It is likely that this event will have a far reaching impact on the industry for the foreseeable future.

A joint task force, the U.S.-Canada Power System Outage Task Force,<sup>18</sup> was charged with investigating the causes of the August 14<sup>th</sup> blackout and recommending ways to reduce the possibility of a future blackout. Recounting in detail the events that led up to the blackout is beyond the scope of this report. In summary, in the Task Force's report, they placed the causes of the "Ohio phase," that precipitated the cascading blackout that moved across the region on that day, into four general groups as follows:

Group 1: FirstEnergy [FE] and ECAR [East Central Area Reliability Coordination Agreement<sup>19</sup>] failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria.

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<sup>16</sup>States that were impacted were Connecticut, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, and Vermont and the Canadian province of Ontario.

<sup>17</sup>This information is based on the report by the joint U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004.

<sup>18</sup>Their final report is, *Ibid.*, "Final Report on the August 14, 2003 Blackout," April 2004.

<sup>19</sup>This area covers Indiana, Kentucky, the lower peninsula of Michigan, Ohio, western Pennsylvania, and West Virginia.

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way.

Group 4: Failure of the interconnected grid's reliability organization to provide effective real-time diagnostic support.<sup>20</sup>

In general, the task force placed the cause of the blackout as from "deficiencies in specific practices, equipment, and human decisions" and, more specifically, as "deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage."<sup>21</sup>

The Task Force outlined 46 recommendations in their final report. These are also arranged into four groups: Group I: Institutional Issues Related to Reliability (14 recommendations), Group II: Support and Strengthen NERC's Actions of February 10, 2004 (17 recommendations), Group III: Physical and Cyber Security of North American Bulk Power Systems (13 recommendations), and Group IV: Canadian Nuclear Power Sector (2 recommendations).

The Task Force's first recommendation is: "Make reliability standards mandatory and enforceable, with penalties for noncompliance." They state that "the single most important" recommendation they make is that "the U.S. Congress should enact the reliability provisions in H.R. 6 and S. 2095 to make compliance with reliability standards mandatory and enforceable."<sup>22</sup> They note that with such legislation, many of their other recommendations could be achieved during implementation of the reliability legislation. This recommendation has not been met and is unlikely to happen, at this time, until sometime during 2005 at the earliest.

Industry restructuring is not addressed directly in the Task Force's report. However, recommendation number 12 is: "Commission an independent study of the

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<sup>20</sup>Ibid., p. 18.

<sup>21</sup>Ibid.

<sup>22</sup>Ibid., p. 2.



relationship among industry restructuring, competition, and reliability.” While it was left unstated directly, clearly the recommended change from the current voluntary reliability standards to mandatory and enforceable standards is being made in recognition of the fact that incentives and conditions have changed in the industry. That is, with vertically structured and regulated utilities, the voluntary standards worked reasonably well. But, as a result of restructuring and the emerging new industry structure, reliability rules and standards need to adjust as well.

### **Transmission System Adequacy**

A related issue to reliability is transmission capacity, expansion, and future investment. This is obviously a critical component of reliability, but it is of critical importance in how competitive power markets perform as well. The transmission system is the backbone of the power infrastructure, which the generation and distribution components and wholesale and retail customers depend. Power system engineers define and separate reliability into two main components, (1) system adequacy, which is the electric system’s ability to supply the aggregate electrical demand and energy requirements of customers at all times; and (2) operating reliability, which is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.<sup>23</sup> However, a third aspect to reliability can now be added, market support or sustenance. Therefore, in the restructured environment, the ability to move power within and across regions reliably requires, in addition to meeting minimum load requirements (reliability definition 1) and without disruptions (reliability definition 2), that there also be sufficient supply for power markets to be relatively stable and reasonably competitive.<sup>24</sup> This requires both sufficient generation *and* transmission.

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<sup>23</sup>Definition used by the North American Electric Reliability Council (NERC), among others.

<sup>24</sup>“Relatively stable” meaning that markets fluctuate with changing conditions within reasonable bounds and proportionately (as fuel prices, economic conditions, etc. change) and “reasonably competitive” means they are operating without excessive supplier market power.

However, transmission expansion is not expected to keep pace with generation capacity and load growth. Between 2003 and 2007 the North American Electric Reliability Council (NERC) expects electricity demand to grow by about 67,000 MW.<sup>25</sup> They are projecting average annual peak demand growth of 1.9 percent for the U.S. for the 2003 through 2012 period. Resource additions over the 2003 to 2007 period is expected to be about 89,000 MW, depending upon the number of merchant plants actually placed in service. Longer-term, more than 117,000 MW of new capacity for the U.S. during the 2003 through 2012 period is expected, or potentially a 14 percent increase over that existing in 2002. However, according to NERC, over 7,400 miles of new transmission (230 kV and above) are proposed to be added through 2007 and about 11,600 miles are expected to be added over the 2003 to 2012 period – a 5.6 percent increase in the total amount of installed transmission in North America for the period. Planned transmission, circuit miles of 230 kV and higher, for the 2003 to 2007 period are expected to increase 3.1 percent for the eastern interconnection and increase 3.5 percent for the western interconnection.

A one-to-one growth rate for transmission and generation capacity and load should not be expected, since transmission investments are “lumpy,” that is, they are made in large increments and can support large amounts of generation investments over time. However, given the expected demand and generation capacity growth, the slower expected transmission expansion rate is, at the very least, a cause for concern. In addition, as NERC states “the transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience.”<sup>26</sup>

A report prepared by Eric Hirst for the Edison Electric Institute and the U.S. Department of Energy suggests that lagging transmission growth rates are not a new

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<sup>25</sup>North American Electric Reliability Council, “2003 Long-Term Reliability Assessment,” December 2003.

<sup>26</sup>NERC, “2003 Long-Term Reliability Assessment,” p. 34.

occurrence.<sup>27</sup> Hirst reports that normalized transmission capacity (MW-miles/MW-demand) grew at an average annual rate of 3.3 percent between 1978 and 1982. In the following 20 years, 1982 to 2002, normalized transmission capacity declined at a rate of 1.5 percent per year.<sup>28</sup> Similarly, transmission miles per GW of demand were increasing at 2.6 percent per year for 1978 to 1982, and decreasing at a rate of 1.6 percent per year over the next 20 years. Hirst also reports that annual investment in transmission facilities by investor-owned utilities (inflation adjusted) fell at an average rate of \$83 million per year between 1975 and 1999. However, from 1999 through 2003, transmission investment *increased* at an average annual rate of \$286 million (the author was not able to explain the sudden reversal in the investment trend.)<sup>29</sup>

Normalizing the NERC transmission capacity data, Hirst reports that normalized transmission capacity declined by almost 19 percent between 1992 and 2002 and is projected to decline by 11 percent for 2002 to 2012.<sup>30</sup> Hirst also shows that normalized transmission capacity declined in all ten reliability regions between 1989 and 2002, ranging from 14 percent to 27 percent declines.<sup>31</sup> Hirst notes that: “[o]f the 416 transmission projects planned for the next 10 years, [footnote omitted] 95% are shorter than 100 miles, with an average length of only 18 miles. These numbers suggest that most planned transmission projects are local in scope and are not intended to address large regional issues.”<sup>32</sup>

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<sup>27</sup>Eric Hirst, “U.S. Transmission Capacity: Present Status and Future Prospects,” June 2004. Prepared for the Edison Electric Institute and the U.S. Department of Energy.

<sup>28</sup>Hirst, p. 7.

<sup>29</sup>Ibid.

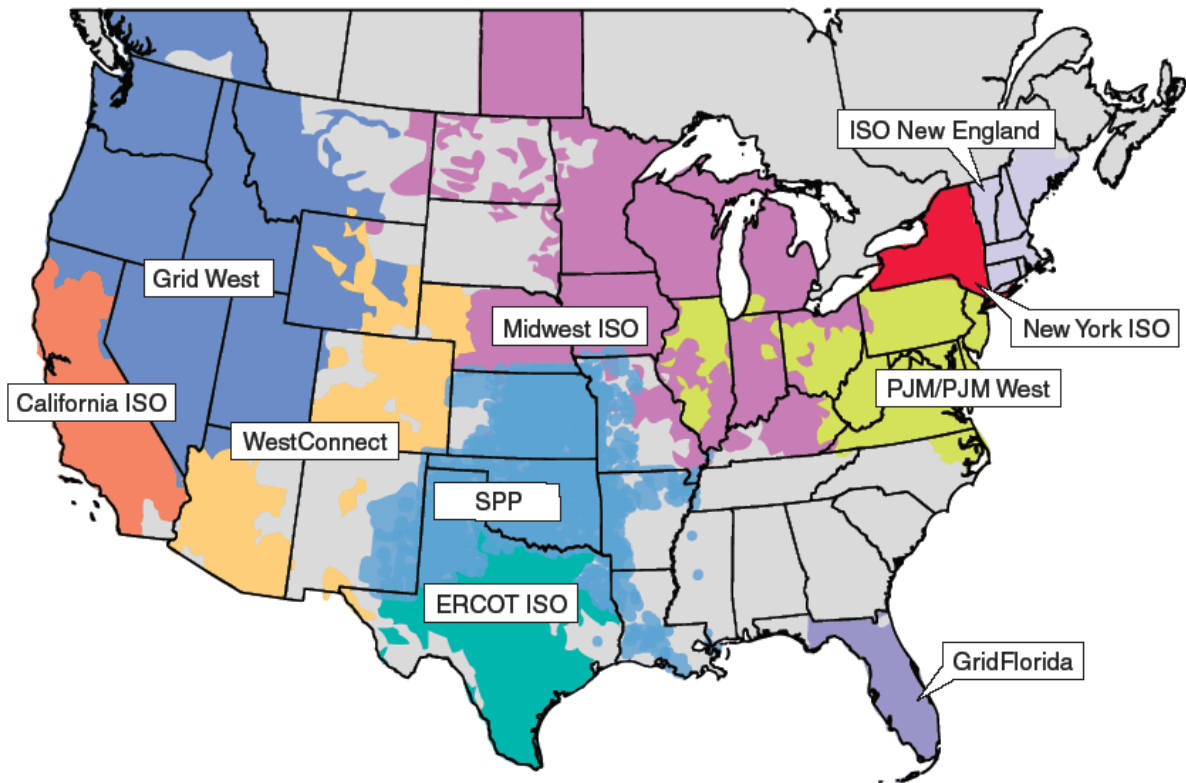
<sup>30</sup>Hirst, p. 9.

<sup>31</sup>Hirst, p. 11.

<sup>32</sup>Hirst, p. 14.

## **Regional Transmission Organization Development and Organization of this Review**

The remaining sections of this report are organized into seven regional sections. The map shown in Figure I.5 identifies the current approved RTOs and ISOs and show the regional transmission organization and the associated power markets discussed in the regional sections. The sections of this report and how they correspond with the region on the map are as follows: Section II, covers the Mid-Atlantic region, which is primarily the original PJM area (eastern Pennsylvania, New Jersey, Maryland, D.C., and a small part of Virginia); Section III, covers the New England region and ISO New England; Section IV, covers New York and that state's wholesale market and the New York ISO; Section V, covers the Midwest, which includes the Midwest ISO and Southwest Power Pool (SPP); Section VI, covers the southeast; Section VII covers Texas and the ERCOT ISO; and Section VIII covers the West. In each regional section, the state retail markets are discussed.



Note: Map includes service territories of transmission-dependent utilities.  
 This map is available to EEI electric company members at [http://www.eei.org/products/rto/maps/rto\\_map.pdf](http://www.eei.org/products/rto/maps/rto_map.pdf) (PDF) or [rto\\_map.ppt](http://www.eei.org/products/rto/maps/rto_map.ppt) (PowerPoint)  
 © 2004 Edison Electric Institute. Service territory data source: POWERmap, 2nd quarter 2002 release, © Platts, a Division of the McGraw Hill Companies.

**Figure I.5.** Approved RTOs and existing ISOs, utility participation as of May 2004.  
 Source: Edison Electric Institute.

## How wholesale market performance is measured

Among the principal reasons<sup>33</sup> 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.

The examination of the performance of the wholesale markets in this report is based on the extent to which this goal of developing a competitive market is being met. Ideally, 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 ease of entry<sup>34</sup> 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 over 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 this perfectly competitive market case, the market price will approximate the marginal cost of supply at the market-clearing quantity.

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 the price takers of the perfectly competitive market. The more a firm can charge a price that exceeds the marginal cost and exert its influence upon the price, the greater the firm’s degree of market power.<sup>35</sup> The price-

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<sup>33</sup>Other reasons include increased use of innovative technologies in generation and more customer options in terms of price, fuel source, and service.

<sup>34</sup>For example, no or little sunk investment costs, where either the investment costs are low or the capital invested can be easily redeployed to another enterprise.

<sup>35</sup>This can be estimated with the “Lerner Index,” which is defined as:  
$$\frac{\text{Price} - \text{Marginal Cost}}{\text{Price}}$$
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

taking competitive firm that has no market power cannot pick its own price or influence it in any significant way. However, there are upper bound limits on price that hold even in the extreme case of market power of an unregulated monopolist that faces no meaningful threat of market entry from rival firms. Such limits reflect 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), nor can a monopolist 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 that encourages consumers to seek alternatives.

Of course, experience tells us that markets are routinely less than ideal or perfect. Suppliers often 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, and is able to do so without using any illegal anti-competitive practices (such as price fixing or in collusion with other firms),<sup>36</sup> this relatively modest impact on price is not likely to lead to calls for corrective regulatory action. Indeed, some corrective actions 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.

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

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it is only 0.02, it is unlikely to raise any calls for governmental action.

<sup>36</sup>These and other anti-competitive practices to raise the price are illegal under Federal law. However, the unilateral exercise of market power by itself is not illegal.

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. 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. Also, mass storage of electricity for later use during peak hours is generally impractical for many regions of the country.<sup>37</sup> 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,<sup>38</sup> is to either physically or economically withhold output from the market. Physical withholding is the actual withdrawal 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.

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<sup>37</sup>Pumped hydro storage, obviously, requires hydro resources to be available, and when it is available, it is usually not a significant portion of the total capacity required to meet demand.

<sup>38</sup>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.



For each of the regions examined in the following sections, to the extent available, analyses of wholesale market performance are summarized and presented in the wholesale discussion. Unfortunately, at this time, not all regions have had a rigorous and independent market performance analysis conducted.

### **How retail market performance is measured**

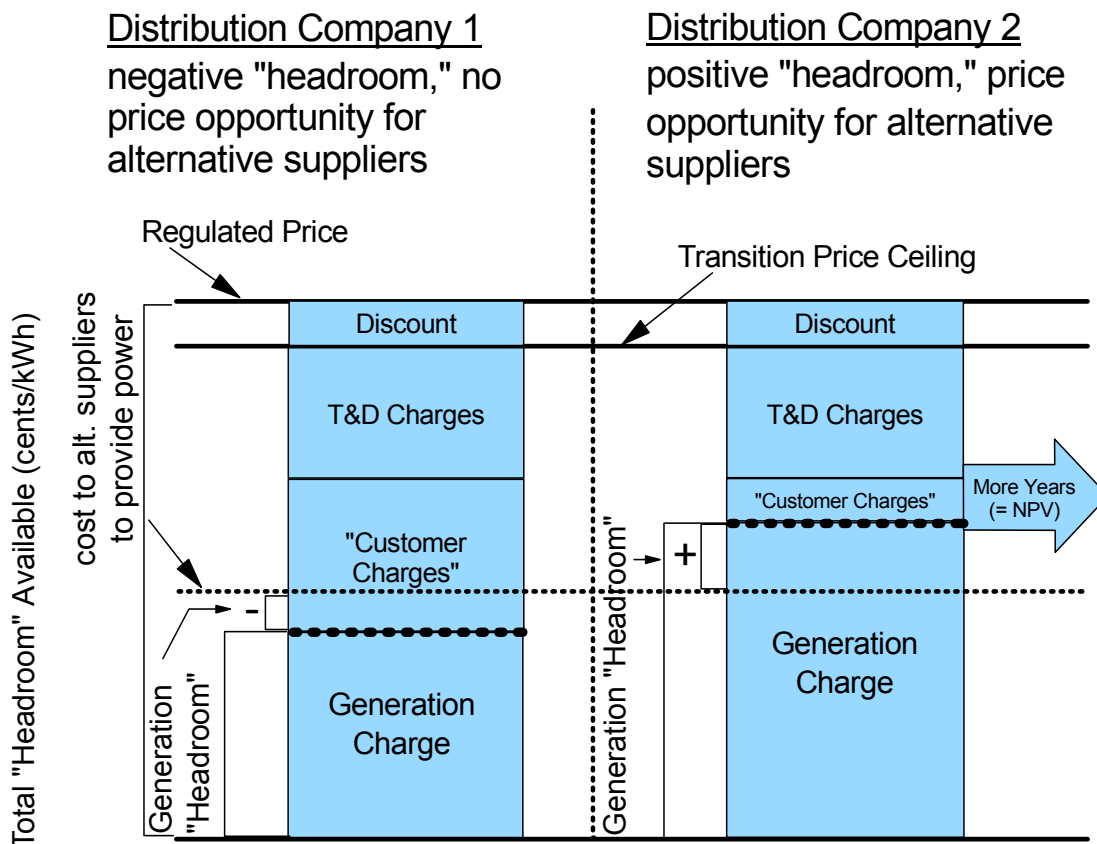
The actual prices paid by retail customers that choose a competitive supplier are not made public. Measuring an actual price trend, and the potential benefits to consumers, is therefore not always directly observable. The review of retail markets summarizes what we can observe in the markets, in terms 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 have selected an alternative supplier, among other factors. These performance measures are, when available, included in the regional summaries in the subsequent sections.

These potential performance indicators in isolation do not determine whether a retail market and its design are succeeding or failing. Rather, considered in tandem with an assessment of wholesale market developments, 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. Most retail markets have overall price constraints that seldom fluctuate along with changing conditions in the wholesale market or are adjusted after a considerable time lag. 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 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 considering entry into a retail market. The effect of the retail price constraints depends 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.

As is illustrated in Figure I.6, the generation charge or price-to-compare, relative to the cost to competitive suppliers to obtain or generate power, will determine the



**Figure I.6.** Examples of two different distribution companies with different generation cost and with the same cost of procuring power for alternative suppliers.

amount of “headroom” available for alternative suppliers to compete. The distribution companies in Figure I.6 have the same beginning regulated price, discount,<sup>39</sup> and transmission and distribution charges. In this hypothetical example, the customer charges are greater for distribution company one on the left side of the figure than distribution company two on the right. To collect the same net present value for both companies (assuming they are the same for both companies), the transition period runs longer for distribution company two. However, the larger customer charge (or “CTC”) for distribution company one results in the generation charge being reduced (in order to remain under the price ceiling<sup>40</sup>), in this case, below the cost to alternative suppliers to either procure power in the wholesale market or to generate it themselves—this cost is represented by the dotted line running across the figure.

Alternative supplier costs also include marketing, risk management, overhead, and normal return-on-investment costs, not only the direct cost of the power. In this first example, alternative suppliers will have to charge a price above what customers would pay if they stayed with the distribution company, therefore, in this case, there is “negative headroom.” In the case of distribution company two in Figure I.6, the generation charge or price-to-compare is above the cost to alternative suppliers to provide power, meaning there is “positive headroom” and an opportunity for these suppliers to entice customers away from the distribution company or default provider.

If there is sufficient headroom, suppliers are able to offer customers an opportunity to save and can entice customers away from the price-to-compare (illustrated by distribution company two).<sup>41</sup> However, the headroom may be too small to cover all the costs of supplying the retail customers, be nonexistent, or even

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<sup>39</sup>Not all states have a discount, of course.

<sup>40</sup>Another way of considering this is to start with the previously regulated rate, then subtract the discount (if any), T&D charges, and the customer charges. Then, what is left over is available for the generation charge.

<sup>41</sup>Of course, as demonstrated by the existence 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 a small subset of customers are willing to pay a premium for these other factors, price is still the dominant consideration for most customers.

negative—that is, where the cost of securing and delivering power to the retail customer exceeds the retail price charged by the distribution company (as illustrated by distribution company 1).<sup>42</sup> Assuming alternative suppliers do not want to operate at a loss for too long, they will not enter or will leave a market under these conditions. In general, of the relative factors of retail price for generation and the wholesale cost of power, the wholesale cost is more volatile. Price fluctuations and volatility, or the future threat of it, can increase the cost to alternative suppliers and be a determining factor in a decision to participate or continue to participate in a market.

Obviously, if the beginning-regulated rate is relatively lower to start with, the amount of available overall headroom (that is, what is available for all the price components) will be relatively low when compared with a higher-rate distribution company. Also, if wholesale prices are relatively high compared to what customers are paying for the price-to-compare, then fewer suppliers will enter the market. This lack of headroom is the primary reason that many retail markets currently have very little activity and, where there is retail market activity, it is primarily within states or distribution companies that had relatively higher costs before restructuring began.

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<sup>42</sup>An extreme example of negative headroom is California, which led one distribution company (PG&E) to the filing for bankruptcy protection and severe 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 own generating 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.

## SECTION II Mid-Atlantic Region

### Mid-Atlantic Wholesale Market: PJM Interconnection<sup>1</sup>

#### Overview and Summary

PJM Interconnection, L.L.C.'s (or PJM) origins date back to 1927 when three companies formed the first power pool, the "Pennsylvania-New Jersey Interconnection." In 1956, three more companies were added and the pool became the "Pennsylvania-New Jersey-Maryland" Interconnection (its beginning as "PJM"). In 1981 PJM added two members, bringing membership to eight companies. Today PJM claims to operate the largest wholesale electric market in the world and coordinates the movement of electricity throughout the mid-Atlantic states and into the Midwest. PJM is a Regional Transmission Organization (RTO) by FERC designation and rulemaking.

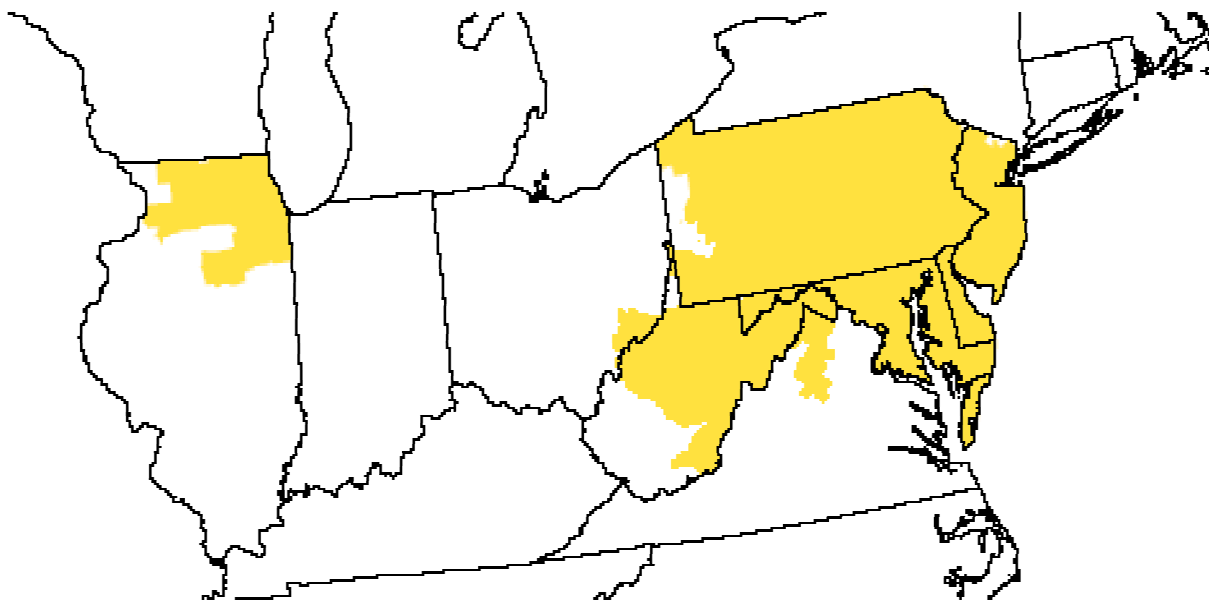
Figure II.1, is a map of PJM's control area (as of May 2004), which now includes all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. PJM's control area currently has approximately 35 million people in it, 800 generation sources of various fuel types, 106,000 MW of generation capacity, peak demand of nearly 87,000 megawatts, 446 million megawatt-hours of annual delivered energy, 25,000 miles of transmission lines, and 275 market participants. Pending regulatory and other considerations, PJM may more than double in size if additional members are integrated into the system to the south and west of its current borders.

Because of its relatively long history as a coordinated power pool, PJM was able to quickly develop into an Independent System Operator (ISO) and perform the market coordination it does today. For this reason PJM currently has the most developed wholesale market in the U.S. and has considerable information on its operations. In

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<sup>1</sup>The introduction and explanatory material presented here on PJM's operations and markets is from various PJM publications on their website, [www.pjm.com](http://www.pjm.com).

addition to operating and monitoring its electricity markets, PJM also plans transmission and generation expansion for the area.



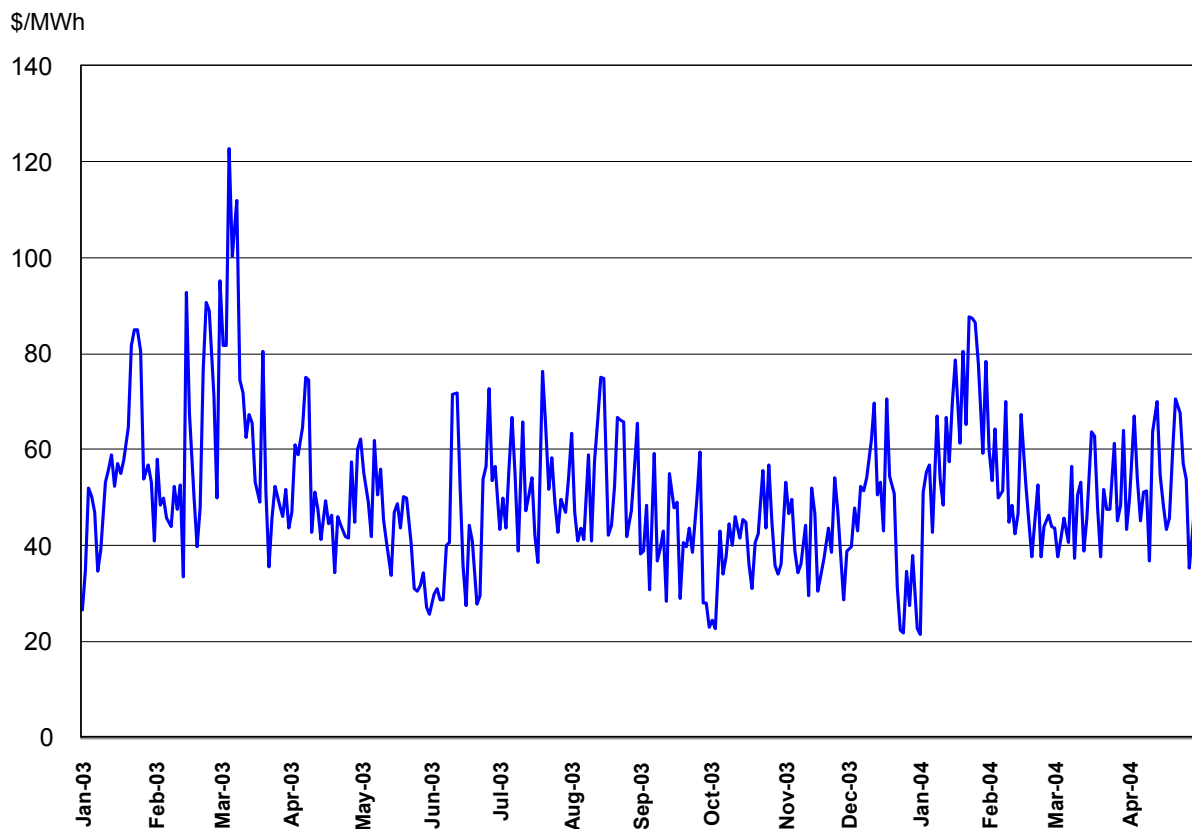
**Figure II.1.** The PJM Interconnection control area—which includes the original PJM region (MAAC Control Zone) and the PJM Western Region.  
Source: PJM Interconnection, May 2004.

### PJM Markets

PJM operates a number of different power markets, including: day-ahead and real-time energy markets; daily, monthly, and multi-monthly capacity credit markets; several ancillary service markets; and monthly Financial Transmission Right (FTR) auction markets. PJM introduced nodal energy pricing with market-clearing prices on April 1, 1998 and nodal, market-clearing prices based on competitive offers on April 1, 1999 (locational marginal pricing or LMP). PJM implemented a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000.

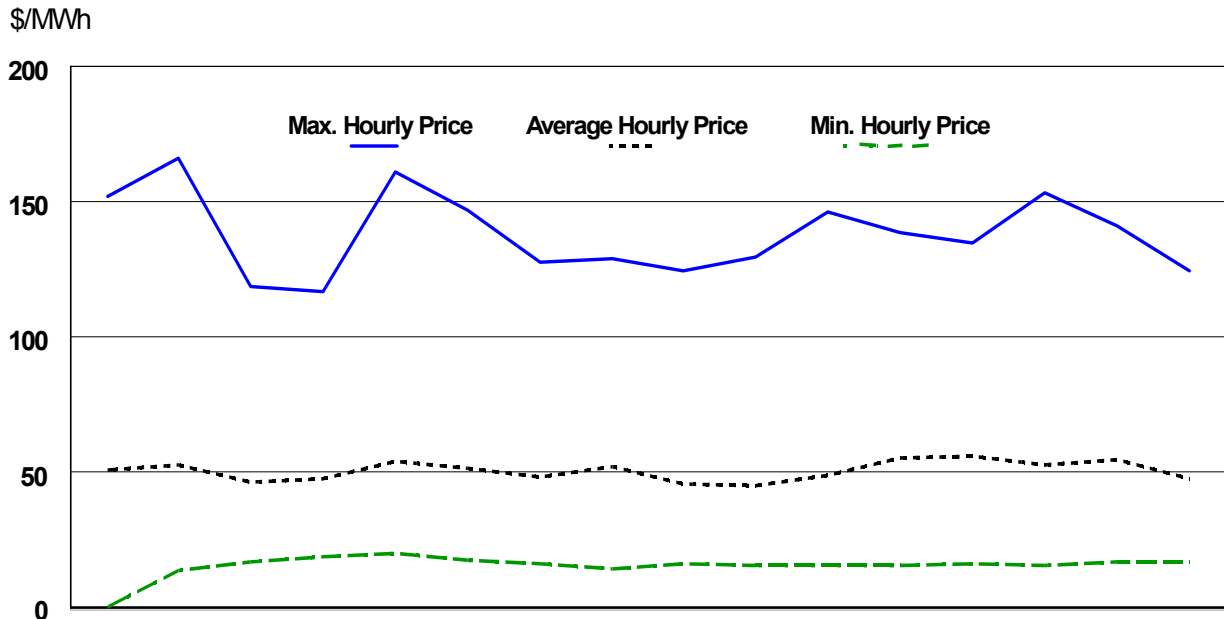
## Energy Markets

The day-ahead energy market is a forward market in which day-ahead locational marginal prices (LMPs) are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transactions submitted in the day-ahead market. The real-time energy market is based on current day operations in which real-time LMPs are calculated at five-minute intervals based on the actual system operating conditions. Figure II.2 plots PJM's daily peak hour average prices in the real-time market (calculated from weighted average hourly LMP prices) for January 2003 through April 2004. As discussed in Section I, the impact of higher natural gas prices in early 2003 and 2004 can be seen in the daily average prices of both years.



**Figure II.2.** Daily peak hour average prices in PJM's Real-Time market (from weighted average hourly LMPs).  
Data source: PJM Interconnection, June 2004.

Figure II.3 shows the peak hour maximum, average, and minimum prices in PJM's real-time market from January 2003 through April 2004. The values are shown in the table below the graph for each peak hour.



Hour	700	800	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000	2100	2200
Max.	152	166	119	117	161	147	128	129	125	130	146	139	135	154	142	125
Avg.	51	53	46	48	54	52	49	52	46	45	49	56	56	53	55	48
Min.	0	14	17	19	20	17	17	14	16	16	16	16	16	16	17	17

**Figure II.3.** Peak hour maximum, average, and minimum prices in PJM's Real-Time market, January 2003 through April 2004.  
Data Source: PJM Interconnection, June 2004.

Buyers and sellers of energy in PJM can decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the day-ahead market or the real-time balancing, or spot



market. Energy purchases can be made over any time frame from instantaneous real-time balancing market purchases to long-term, multi-year bilateral contracts. Purchases may be made from generation located within or outside the PJM control area. Generation owners can sell their output within the PJM control area or outside the control area and can use generation to meet their own loads, to sell into the spot market or to sell bilaterally. Generation owners can sell their output over multiple time frames from the real-time spot market to multi-year bilateral arrangements.

### Capacity Markets

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources equal to the peak load that it serves plus a reserve margin. LSEs can acquire capacity by buying or building units, by entering into bilateral arrangements with terms determined by the parties, or by participating in the capacity credit markets operated by PJM. Collectively, these arrangements are now known as the Unforced Capacity Market (UCAP). The PJM capacity credit markets (CCM) provide a mechanism to balance the supply of and demand for capacity not met through the bilateral market or through self-supply. Capacity credit markets are intended to provide a transparent, market-based mechanism for new, competitive LSEs to acquire the capacity resources required to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. PJM's daily capacity credit markets enable LSEs to match capacity resources with changing obligations caused by daily shifts in retail load. Monthly, multi-monthly, and interval capacity credit markets enable longer-term capacity obligations to be matched with available capacity resources. Prices and performance, including a significant problem with manipulation of the capacity credit markets, are discussed below.

### Ancillary Services: Regulation Market

Regulation is one of six ancillary services defined by the FERC in Order No. 888. Regulation is required to match generation with short-term increases or decreases in load that would otherwise result in an imbalance between the two. Longer-term

deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Market participants can acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally. The market design implemented by PJM provides incentives to owners based on current, unit specific opportunity costs in addition to the regulation offer price. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of \$100 per MW, plus opportunity costs. A regulation market was introduced on June 1, 2000, and modified on December 1, 2002.

#### Ancillary Services: Spinning Reserve

Spinning reserve is an ancillary service defined as generation synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can be provided by a number of sources including steam units with available ramp (incidental spinning), condensing hydro units, condensing combustion turbines (CTs), CTs running at minimum generation, and steam units scheduled a day ahead to provide spinning reserves. PJM introduced a market for spinning reserves on December 1, 2002.

#### Financial Transmission Rights

A Financial Transmission Right (FTR) is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the transmission grid is congested in the day-ahead market and differences in day-ahead Locational Marginal Prices (LMPs) that result from the dispatch of generators out of merit order to relieve the congestion. Each FTR is defined from a point of receipt (where the power is injected onto the PJM grid) to a point of delivery (where the power is withdrawn from the PJM grid). For each hour in which congestion exists on the transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Transmission Congestion Charges collected from the market participants.

FTRs are designed to provide a hedge against congestion charges in the day-ahead market for firm transmission service customers, who pay the costs of the transmission system, including any congestion charges. PJM provides three ways to acquire FTRs: the annual FTR auction, the monthly FTR auction, and the FTR secondary market. The annual auction uses a multi-round auction process that offers for sale the entire transmission entitlement available on the PJM system on a long-term basis. The proceeds from the annual FTR auction are allocated through the Auction Revenue Rights (ARR) mechanism. The ARRs are allocated to network transmission customers and to firm point-to-point transmission service customers for the annual planning period. ARR holders can elect to directly convert an ARR into an FTR instead of bidding in the auction. PJM completed the first annual auction of FTRs in May 2003. The monthly FTR auction offers for sale any residual transmission entitlement that is available after FTRs are awarded from the annual FTR auction and also allows market participants an opportunity to sell FTRs they are holding. Before the annual auction was instituted, FTRs were allocated annually to firm transmission service customers and remaining FTRs were auctioned in the monthly auction. The FTR secondary market is a bilateral trading system that facilitates trading of existing FTRs between PJM members.

FTRs are financial entitlements that enable holders to receive revenues (or charges) based on transmission congestion measured as the hourly energy locational marginal price differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basic risk associated with delivering energy from one bus or aggregate to another. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

The hourly value of an FTR is based on the FTR megawatt reservation and the difference between day-ahead LMPs at the point of delivery and the point of receipt designated in the FTR. An FTR *obligation* is positive when the path designated in the FTR is in the same direction as the congested flow. However, an FTR obligation is negative (a charge or liability) when the designated path is in the opposite direction of the congested flow. An FTR *option* is also positive when the path designated in the FTR is in the same direction as the congested flow, but an FTR option's value is zero when the designated path is in the direction opposite to the congested flow. The option is intended to eliminate the risk from holding an FTR when transmission congestion occurs in the opposite direction of the path specified in the FTR.

FTRs are issued through PJM's simultaneous feasibility test that determines the amount of FTRs for each participant based on anticipated power transactions and transmission requirements and the system's ability to accommodate these requirements. When the actual system conditions result in more congestion than what was expected, there may be an insufficient number of FTRs issued to cover all actual congestion, a condition referred to as "unhedgeable congestion." It is unclear at this time just how much congestion on the PJM system is "unhedgeable."

While this situation may be occasional, there are transmission system constraints, such as with a number of "load pockets" scattered throughout PJM and in other parts of the country that could result in significant congestion charges. It is also not clear just how common and pervasive these types of constrained conditions are throughout the country. The western U.S., for example, has many isolated load pockets, including some large urban areas that are separated by long distances. Supporters of the LMP/FTR concept have argued that the process sends the correct economic incentive to build generation in the transmission-constrained area or to find ways to relieve the congestion with additional transmission capacity. However, critics have argued that adding additional transmission lines may require the siting of new transmission rights-of-ways, which is always difficult and costly. Even additional capacity on existing rights-of-ways are often difficult and costly as well. Moreover, as critics note, it is already known that additional generation is likely needed in the area

and that additional transmission capacity would ameliorate the congestion problem, so the additional cost from the LMP “incentive” is superfluous and will only result in higher costs for customers.

### Market Performance Update

Several analyses summarized in previous years’ Performance Reviews by Mansur<sup>2</sup> and Bushnell and Saravia<sup>3</sup> indicated that there were appreciable levels of supplier market power in PJM markets. However, these studies used data from early in the operation of the markets and, while instructive on methodology and market design issues, are of limited value to judge how these market have preformed recently. There have been changes in market design and operation in the last several years and market participants have become more familiar with the operation through experience. This will likely affect both the ability of market participants to find ways to profitably use the rules and procedures to their advantage and also time for PJM, FERC and other participants to respond with changes to counteract strategies that may be harmful to customers’ and other participants’ welfare. Unfortunately, there are no recent comprehensive, independent, and academically defensible analyses of PJM markets.

PJM’s own Market Monitoring Unit (MMU) estimates a price-cost markup index, that is basically a Lerner index<sup>4</sup> that is load-weighted and normalized. They calculate and present average monthly load-weighted markup indices that generally are at levels that would not raise any particular concern about the performance of PJM’s markets. In

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<sup>2</sup>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. Also, for a more recent analysis (using 1999 market data), see Mansur, "Vertical Integration in Restructured Electricity Markets: Measuring Market Efficiency and Firm Conduct," Center for the Study of Energy Markets Working Paper, University of California Energy Institute (CSEM WP 117), October 2003.

<sup>3</sup>Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

<sup>4</sup>The markup or Lerner index is calculated as:  $(\text{Price} - \text{Marginal Cost})/\text{Price}$ , as discussed in Section I.

the MMU's reports of the years 2001, 2002, and 2003<sup>5</sup> the average markup for both 2001 and 2002 was calculated to be 0.02 (that is, 2 percent of the price is mark-up above marginal cost) and 0.03 (3 percent of price) for 2003. The maximum monthly markup was 0.05 (5 percent) for January 2001, 0.04 (4 percent) for July 2002, and 0.06 (6 percent) for February 2003. The minimum monthly market was less than 0.01 (less than 1 percent) for November 2001 and again for several months in 2002, and 0.01 (1 percent) for August 2003. The MMU also calculated monthly markups assuming that there is a 10 percent markup over cost, since generators in PJM are allowed to provide cost-based offers with up to a 10 percent markup over cost. An adjusted markup calculation removes the assumed potential 10 percent increase over cost and results in the average markups to increase to 0.11 (11 percent) for both 2001 and 2002, and 0.12 (12 percent) for 2003. The adjusted monthly maximum of 0.13 (13 percent) in January 2001, again in July 2002, and 0.15 (15 percent) in February 2003 and a minimum of 0.09 (9 percent) for October 2001, 0.10 (10 percent) for several months in 2002 and again in 2003.

The MMU provides little description on how their markup index is calculated, therefore, their methodology cannot be fully evaluated without more detail. They do indicate that when calculating the index, they compare the marginal unit's price offer to the cost of the highest marginal cost unit operating, not the marginal cost associated with the marginal unit.<sup>6</sup> This may simplify the calculation, but it will not pick up any physical or economic withholding strategies (since, as discussed in Section I, they are intended to force the dispatch of the higher marginal cost units to drive up the price) and will likely understate the markup index (since the difference between price and marginal cost is reduced).

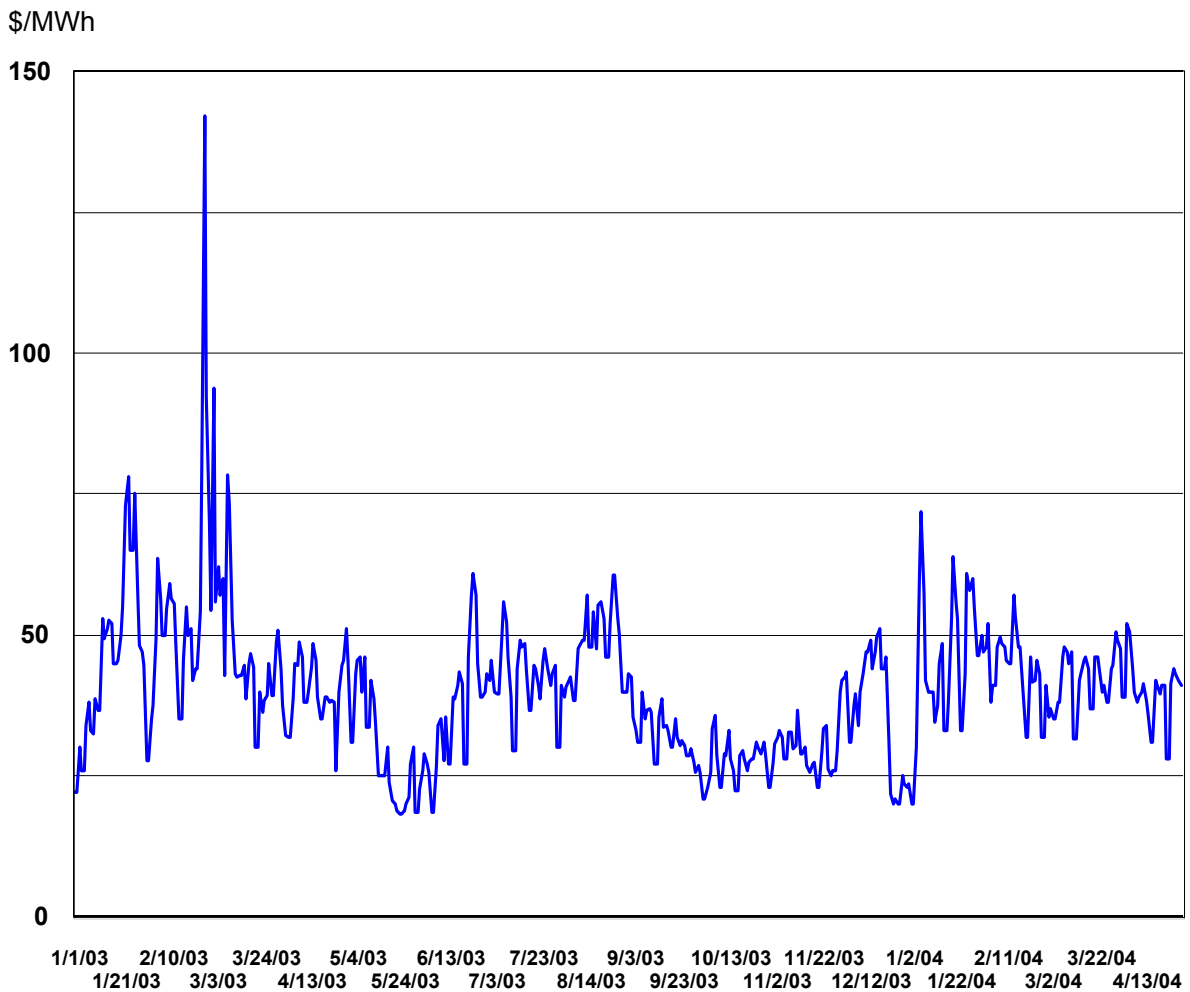
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<sup>5</sup>Market Monitoring Unit, PJM Interconnection, L.L.C, "PJM Interconnection State of the Market Report 2001," June 2002; Market Monitoring Unit, PJM Interconnection, L.L.C, "2002 State of the Market Report," March 5, 2003; and Market Monitoring Unit, PJM Interconnection, L.L.C, "2003 State of the Market," March 4, 2004.

<sup>6</sup>MMU, "2003 State of the Market," p. 53.

## Mid-Atlantic Wholesale Market: VACAR

VACAR is a North American Electric Reliability Council (NERC) subregion that includes most of Virginia, North Carolina, and South Carolina, currently outside the PJM region. Figure II.4 charts wholesale prices for the region reported by Platts in *Megawatt Daily* for January 2003 through April 2004. Reported trading volume for the area's wholesale market is relatively thin, therefore, prices are based on few reported trades.



**Figure II.4.** Platts VACAR volume weighted average index prices, January 2003 through April 2004.

Data source: Platts McGraw-Hill, *Megawatt Daily*, 2003 and 2004.

## Mid-Atlantic Retail Markets

### Maryland

Retail access in Maryland began for all customers in the four investor-owned utilities on July 1, 2000. Through settlements reached with the state's investor-owned utilities, most residential customers had rate decreases between three percent and 7.5 percent below rates in effect in June 1999 and had fixed Standard Offer Service prices for the generation supply portion of their bills for customers that do not choose an alternative supplier. This Standard Offer Service supplied by the utilities expires at different times by customer classes and utility company. The schedule for phase-out of Standard Offer Service is shown in Box II.1.

After the fixed price standard offer service expires, default rates for customers who do not choose an alternative supplier and continue to receive generation supply from their local utility, will be based on bids received in a competitive bidding process to serve these non-choosing customers.

Residential customers of PEPCO and DPL/Conectiv began to receive bid-based Standard Offer Service beginning July 1, 2004 for customers who do not choose a competitive electric supplier. In April 2004, the Maryland PSC announced the results of the bidding process. According to the Maryland PSC, the bidding process involved 25 wholesale electric suppliers offering electric supply 4 to 5 times in excess of the load that was solicited. As a result of the bidding process, PEPCO residential customers will have the power supply portion of their bills increased by 26 percent and average annual

#### **Box II.1. Standard Offer Service end dates by utility company.**

- **Allegheny Power (APS):** July 1, 2008 for residential customers; July 1, 2004 for non-residential customers.
- **Baltimore Gas and Electric (BGE):** July 1, 2006 for residential customers; either July 1, 2002 (Schedule P C&I) or July 1, 2004 (remaining C&I).
- **Delmarva Power and Light (DPL or Conectiv):** July 1, 2004 for residential customers; July 1, 2003 for non-residential customers.
- **Potomac Electric Power (PEPCO):** July 1, 2004 for all customers.



bills increased by approximately 16 percent (an increase of \$164.28 for the average residential annual bill). Total bills for PEPCO small commercial customer will increase by approximately 13 percent; medium-sized commercial customer bills will increase between 25 to 30 percent; large-sized commercial customers bills will increase approximately 48 percent to 57 percent. Exact customer increases depend on customer class and individual usage. These increases are only for the generation component of the total bill.

DPL/Conectiv residential customers will have the power supply portion of their bills increased by 19 percent and average annual electric bills will increase approximately 12 percent (an increase of \$130.80 for the average residential annual bill).

Generation supply prices for residential customers of Baltimore Gas and Electric Company continues to be frozen until July 2006 and residential customers of Allegheny Power will have frozen supply prices through 2008.

As summarized in Table II.1, nearly all the residential customer switching to alternative suppliers in Maryland has been in Potomac Electric Power's service area. However, the percentage of residential served by an electric supplier decreased from almost 16 percent in April 2003 to 11.6 percent in April 2004. Non-residential customers enrolled with an alternative supplier in Potomac Electric's service area also declined from just over 21 percent to 17.5 percent. There was no significant percentage of residential customers enrolled with an alternative supplier in any of the other three service areas. There was a significant increase in the percentage of non-residential customers choosing a supplier in Conectiv Power Delivery's area, from under two percent to over nine percent—however, that is a relatively low level overall. Only a very small percentage (less than one percent) of the non-residential customers had switched in Baltimore Gas & Electric's area and none had in Allegheny Power area in either year. Statewide, for April 2004, about three percent of all customers have chosen an electric supplier, less than three percent of all residential customers and 5.4 percent of the non-residential customers.

**Table II.1.** Maryland percentage of customers enrolled with an electric supplier

Utility	Residential		Non-Residential		Total	
	April 2003	April 2004	April 2003	April 2004	April 2003	April 2004
<b>Allegheny Power</b>	0%	0%	0%	0%	0%	0%
<b>Baltimore Gas &amp; Electric</b>	0%	0%	0.5%	0.7%	0.1%	0.1%
<b>Conectiv Power Delivery</b>	0%	0.1%	1.6%	9.4%	0.2%	1.3%
<b>Potomac Electric Power</b>	15.7%	11.6%	21.4%	17.5%	16.2%	12.2%
<b>Total</b>	3.8%	2.8%	5.1%	5.4%	3.9%	3.1%

Source: Maryland Public Service Commission, for months ending April 25, 2003 and April 30, 2004.

As summarized in Table II.2, two areas had offers from alternative suppliers to residential customers, Potomac Electric Power and Baltimore Gas & Electric. No area in the state had an offer that was below the price-to-compare. Four areas had no offers at all. The one supplier in Baltimore Gas & Electric and Potomac Electric Power (PEPCO) service territories that was making the four offers was Pepco Energy Services, which was offering a “standard electricity” service, and 10 percent, 51 percent, and 100 percent “green electricity” offers. These offers were all above the price-to-compare. Pepco Energy Services is a wholly owned subsidiary of Pepco Holdings, Inc., which was formed by the merger between Pepco and Conectiv.

**Table II.2.** Competitive offers to residential customers in Maryland.

Utility	Number of Competitive Suppliers		Total Number of Offers from Competitive Suppliers		Number of Offers Below the Price-to-Compare	
	May 2003*	2004*	May 2003*	2004*	May 2003*	2004*
<b>Allegheny Power</b>	0	0	0	0	0	0
<b>Baltimore Gas &amp; Electric</b>	1	1	2	4	0	0
<b>Choptank Electric Cooperative</b>	0	0	0	0	0	0
<b>Conectiv Power Delivery</b>	0	0	0	0	0	0
<b>Potomac Electric Power</b>	2	1	3	4	1	0
<b>Southern Maryland Electric Cooperative</b>	0	0	0	0	0	0

\*2003 numbers from May 14, 2003. 2004 numbers for Allegheny Power, BG&E, and Choptank Electric Coop from May 2004, Conectiv Power Delivery last reported May 14, 2003, Potomac Electric Power from November 2003, and Southern Maryland Electric Coop from December 2003.

Source: Maryland Attorney General, 2003 and 2004.

### District of Columbia

The Council of the District of Columbia passed legislation at the end of 1999 allowing the D.C. Public Service Commission to implement retail access. Retail access began for all customers in the District on January 1, 2001. By Commission order, there was a 7 percent reduction of PEPCO rates for residential customers and a 6.5 percent reduction of rates for commercial customers that was implemented in three phases in

2000 and 2001.<sup>7</sup> The District is also served by Potomac Electric Power (PEPCO), which completed the sale of all its generation plants by January 2001. PEPCO sold most of its electric power plants and other generation assets to Mirant Corporation. Mirant now owns four generating plants, a combined 5,256 MW, in the D.C. area. (Mirant filed for bankruptcy protection under Chapter 11 on July 14, 2003.) PEPCO also transferred ownership of two District of Columbia plants to its unregulated subsidiary, Potomac Power Resources, Inc. These two plants are operated by Mirant. PEPCO also sold its 9.7 percent interest in the Conemaugh Generation Station to Allegheny Energy, Inc. and PPL Corporation. In December 2000, PEPCO signed a four-year contract with Mirant Corporation to buy the power needed for its customers at prices below PEPCO's average cost of production. The Commission ordered PEPCO to distribute "divestiture sharing credits" to customers after PEPCO sold its generation assets and also a "generation procurement credit" for a share of the difference between the contract payment to Mirant and PEPCO's standard offer generation revenue.

Overall rate caps are in effect until February 7, 2007 for low-income customers and until February 7, 2005 for all other residential and commercial customers. PEPCO will provide generation service to its customers until February 2005. As part of the Commission's approval of the merger of PEPCO and Conectiv, distribution rates are capped at the February 7, 2005 levels for non-low-income customers from February 8, 2005 through August 7, 2007 and for low-income customers through August 31, 2009.

The Commission reported that, as of January 2004, two alternative suppliers—Pepco Energy Services (PES, an unregulated subsidiary of PEPCO Holdings, Inc.) and Washington Gas Energy Services (WGES, an unregulated subsidiary of Washington Gas)—were serving the District's residential sector. However, WGES is not accepting any new customers at the time. PES, WGES and BGE Homes are serving the District's non-residential (commercial) sector. PES announced in early May 2004 that the renewal rate for standard residential generation and transmission service will be over 41

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<sup>7</sup>A chronology of Commission actions and other key events in D.C. retail access is at: [www.dcpsc.org/customerchoice/whatis/electric/elec\\_restruc.shtm#Top](http://www.dcpsc.org/customerchoice/whatis/electric/elec_restruc.shtm#Top)

percent higher than the current rate for contracts that expire in July 2004. Rates for new residential customers were announced to be 59 percent higher than the current rate. PES customers have the option to return to PEPCO's capped prices (capped until February 2005), but they must inform PES in writing to terminate their contract—or they will automatically be renewed at the higher PES rate. The PES renewal rate is about 37 percent above the PEPCO average annual residential generation and transmission rate or the “price-to-compare” as defined in the District.

Table II.3 shows the current percent of customers and load served by alternative suppliers in the District. The percentage of both residential and non-residential customers served by alternative suppliers decreased somewhat from May 2003 to May 2004. The percent of residential customers dropped to under nine percent and under 15 percent for non-residential customers. However, the non-residential load (mostly commercial, in MWh) served by an alternative supplier remained above 40 percent.

**Table II.3.** Percent of customers and load served by alternative suppliers in the Dist. of Columbia.

Percent Period	Residential		Non-Residential		Total	
	Customers	Load (MWh)	Customers	Load (MWh)	Customers	Load (MWh)
<b>May 2002</b>	5.3%	5.3%	19.5%	55.0%	7.0%	48.5%
<b>May 2003</b>	11.2%	13.7%	16.5%	45.7%	11.9%	41.5%
<b>May 2004</b>	8.8%	10.6%	14.2%	41.2%	9.5%	36.7%

Source: District of Columbia Public Service Commission, June 2004.

### New Jersey

As reported in the two previous years' reports, New Jersey had some activity early in the state's retail access program. One utility, Conectiv, reached almost 12 percent of the non-residential customers and almost six percent of residential customers being served by alternative suppliers, as reported for November 2000. Two other utilities had about six percent of the non-residential customers that had chosen an

alternative, also reported for November 2000. About one year later, by October 2001, all customer switching by non-residential and residential customers had dropped to less than one percent for all companies in mid-2003. As Table II.4 shows, the percentage of customers choosing a supplier remained relatively low. For August 2004, residential customer percentages all remained at fractions of one percent and non-residential customer percentages, while much larger than those reported for July 2003, were all less than two percent. Because many larger non-residential customers have chosen an alternative supplier, for reasons that are explained below, the total state load (MW) being served by alternative suppliers was nearly 16 percent for August 2004.

The residential customer percentage for Jersey Central Power & Light Company (JCP&L) jumped from barely registering above zero in 2003 to over 11 percent as reported for June 2004. This was 107,339 residential customers in JCP&L's territory. However, JCP&L's "Green Pilot Program" accounts for the increase in the residential switching and the temporary percentage jump. This program was approved by the New Jersey Board of Public Utilities (the Board) in December 2002. The Board ordered JCP&L to requested competitive proposals from qualified bidders to supply green power to serve 200 MW of retail load or electric service for 150,000 residential customers, whichever is greater. The Pilot Program was set to run for ten months from August 1, 2003 through May 31, 2004. The winning prices from the bidding process were averaged with the prices obtained through the "Fixed Price" auction (described below), to determine JCP&L's system-wide rates. The low bidder was FirstEnergy Solutions Corp. with a bid of 5.444 cents/kWh to supply the entire program load. (FirstEnergy Solutions, is an affiliate of FirstEnergy Corp., which is also the parent company of JCP&L). When the results were averaged with the auction prices, the winning Pilot Program bid increased the price used to determine customer generation rates only by .307 percent – for a final price of 5.231 cents/kWh.

The Board had decided that if there was insufficient customer enrollment, the program allotment would be filled through random customer assignment where residential customers will be randomly assigned to the Green Pilot Program. Customers

were given an opportunity to opt-out, if they so chose.<sup>8</sup> In October of 2003, the Board noted that only 5,700 customers volunteered for the program and 24,100 customers that were assigned to it chose to opt-out of the program. Because of the disappointing response, the program was allowed to expire on May 31, 2004, as scheduled.<sup>9</sup> The number of customers that opted out between October 2003 and May 31, 2004, when the program expired, was not provided. It is likely, however, the Pilot Program accounted for most of the 107,339 residential customers that were reported to have chosen an alternative supplier and explains why the percentage of customers dropped back to what it was for July 2003. (The number of customers dropped to just 340, of 931,940 residential customers in total, as reported in August 2004.)

**Table II.4.** Percent of New Jersey customers served by alternative suppliers.

Distribution Company	Residential			Non-Residential			Total		
	July 2003	June 2004	Aug. 2004	July 2003	June 2004	Aug. 2004	July 2003	June 2004	Aug. 2004
<b>Conectiv</b>	0.08%	0.07%	0.07%	0.31%	1.43%	1.43%	0.11%	0.24%	0.24%
<b>JCP&amp;L*</b>	0.04%	11.52%	0.04%	0.04%	2.16%	1.88%	0.04%	10.46%	0.24%
<b>PSE&amp;G</b>	0.05%	0.05%	0.05%	0.04%	1.64%	1.83%	0.05%	0.27%	0.29%
<b>Rockland</b>	0%	0%	0%	0%	0.26%	0.26%	0%	0.03%	0.03%
<b>Statewide Total</b>	0.05%	3.39%	0.05%	0.08	1.72%	1.76%	0.06%	3.18%	0.27%

Source: New Jersey Board of Public Utilities, July 29, 2003, June 17, 2004, and August 13, 2004.

\*Includes residential customers in the JCP&L Green Pilot Program.

In February 2002, the New Jersey Board of Public Utilities (BPU) approved the results of the first Basic Generation Service (BGS) auction to meet the electric demands

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<sup>8</sup>New Jersey Board of Public Utilities, Docket No. EX01110754, February 20, 2003.

<sup>9</sup>New Jersey Board of Public Utilities, Docket No. EO03050394, October 22, 2003.

of customers who have not selected an alternative electric supplier or who are dropped by a third-party supplier. More than twenty companies participated in the auction held on the Internet from February 4 to February 13, 2002. During this auction firms bid simultaneously to supply capacity, energy, and ancillary services to customers at a competitive price per kWh for the period of August 1, 2002 through July 31, 2003. This auction was conducted under the requirement of New Jersey's restructuring law that utilities facilitate competition of the supply of electricity to customers who have not switched companies under deregulation. The price results of the 2002 auction are shown in Table II.5. The auction was for full customer requirements, including energy, capacity, load following, ancillary services and transmission. Each utilities' load was broken down into slices or "tranches" that are approximately 100 MWs. The utilities still maintain customer services such as billing and metering.

The price results of the 2003 "Fixed Price" auction, held in February 2003, for BGS for small to medium-sized customers are also shown in Table II.5. Another separate auction was held this time to determine hourly- priced service for approximately 1,750 larger customers, where energy prices are based on PJM's hourly prices, the results of this "Commercial Industrial Energy Prices" (CIEP) auction are

**Box II.2. The New Jersey Auction Process\***

- Internet-based, simultaneous multi-round descending clock auction
- Basic Generation Service load for all four NJ electric utilities is auctioned simultaneously
- Auction is a "reverse auction" or procurement auction – where bids are offers to supply at a price (not to buy) – bid offers decline through auction
- Auction is conducted in a series of rounds, each with an announced starting and ending time
- Auction ends when the supply bids equal the BGS quantity needed for each of the four utilities
- Auction approval process:
  - auction results must be addressed by the NJBPU by the end of the second business day after the close of the auction
  - auction results must be accepted or rejected for all electric utilities in entirety or for none of them

\*From presentation by Commissioner Frederick F. Butler, "Acquiring Electric Supply: An Overview of the New Jersey Basic Generation Service Auction Solicitation Process," April 29, 2004.



shown in Table II.6. Again, Internet auctions determined BGS for all the state’s distribution companies. This was to provide BGS supply for the period from August 1, 2003 through May 31, 2004. The fixed price auction (for the smaller customers) concluded after 14 rounds of bidding and had 15 winning bidders sharing approximately 15,500 MW of load. The auction for hourly service or CIEP (for larger customers) had 15 rounds with eight bidders for the 2,500 MW of available load. New Jersey is currently the only state in the country using such an Internet-based auction procedure to determine prices for non-choosing customers. (Maine, as summarized in Section III, uses a competitive bidding process for its “standard offer” generation service.) Except for Rockland, all prices were somewhat higher than those determined in the 2002 auction.

**Table II.5.** Price results from the 2002, 2003, and 2004 “Fixed Price” auctions for small to medium-sized customers (cents/kWh).

	<b>2002 Auction</b>	<b>2003 Auction</b>		<b>2004 Auction</b>	
<b>Term</b> <b>Company</b>	12 Month	10 Month	34 Month	12 Month	36 Month
<b>Conectiv</b>	5.12	5.260	5.529	5.473	5.513
<b>JCP&amp;L</b>	4.87	5.042	5.587	5.325	5.478
<b>PSE&amp;G</b>	5.11	5.386	5.560	5.479	5.515
<b>Rockland</b>	5.82	5.557	5.601	5.566	5.597

Source: New Jersey Board of Public Utilities, February 2003 and 2004.

A third BGS auction was held in February 2004 for service beginning on June 1, 2004. The results are again shown in Table II.5. The Board notes that on an annual basis, residential customers of PSE&G, Rockland Electric, and JCP&L will have small decreases, ranging from 0.5 percent to 1.5 percent. Conectiv residential customers will see a slight increase of 0.7 percent. The 2004 auction was similar to 2003, with two simultaneous multiple round auctions, a fixed price auction for small and medium sized customers and one for hourly-priced service for about 1,750 of the state’s largest

electric customers (CIEP auction). According to the New Jersey Board, for the fixed price customers, 33 percent of the energy will be for a 12 month commitment and 33 percent will be for 36 months – with the balance of the fixed price demand being met under contract until May 2006. The Board required participation in the hourly auction for all commercial and industrial customers with a peak load share of 1500 kW and greater (which added about 128 accounts to the CIEP class in the 2004 auction). The Board allowed other commercial and industrial customers to volunteer to participate in the hourly auction—approximately 100 customers volunteered to participate statewide. The Fixed Price auction ran from February 2, 2004 to February 10 and had 71 rounds of bidding with 12 winning bidders. The hourly or CIEP auction also began on February 2, 2004 and ended on February 6 after 52 rounds of bidding with six winning bidders. The results of the hourly or CIEP auction for 2004 are also shown in Table II.6.

**Table II.6.** Price results from the 2003 and 2004 “Commercial Industrial Energy Prices” (CIEP) auctions for large customers (Dollars per MW-day).

	<b>2003 (10 months)</b>	<b>2004</b>
<b>Conectiv</b>	56.10	49.90
<b>JCP&amp;L</b>	65.25	54.98
<b>PSE&amp;G</b>	60.00	52.01
<b>Rockland</b>	59.80	57.96

Source: New Jersey Board of Public Utilities, February 2003 and 2004.

The approximately 1,750 larger CIEP customers pay the auction price, plus an administrative fee and an energy price based on PJM’s hourly prices. Unless, of course, these customers make provisions with a supplier of their own choice. In contrast, the Fixed Price customers pay the auction-based fixed price result if they do

not choose a supplier. As of December 31, 2003, 56 percent of the CIEP customers switched to an alternative supplier or 76 percent of the total CIEP load.<sup>10</sup>

On August 1, 2003, the auction-determined generation prices translated directly to the rates customers pay, since the transition period ended and the rate caps and discounts ended. The New Jersey Board of Public Utilities determined the post-transition, non-generation portion of rates for customers in July 2003. Beginning August 1, 2003, excluding the BGS portion, all Conectiv customer classes had an average rate increase of approximately 4.7 percent. The estimated average BGS increase for all fixed-price customer classes is about 3.4 percent, resulting in a total rate increase of 8.1 percent. The average residential customer had an increase of approximately 6 percent on their monthly bill (the average residential bill would increase from \$85.77 per month to \$90.93 per month). This includes deferred balances accrued by Conectiv during the transition period when the rate cap was in effect and the company could not recover all of its costs incurred to supply its customers (as New Jersey's restructuring law allows recovery after the four-year transition period). The Board also determined that Rockland's (a company that also had deferred balances) rates for the average residential customer would increase by 15.4 percent. This includes the estimated 11.3 percent increase in BGS charges and resulted in a monthly bill increase from \$85.21 per month for the average residential customer to \$98.36 per month. The Board also authorized PSE&G (again with deferred energy costs) an increase of approximately 15 percent for the residential customer class. The Board modified the rate design in a proposed settlement to assure that the majority of residential customers receive no more than a 15 percent increase on an overall annual basis, including BGS prices. For Jersey Central Power & Light, the Board approved an average annual increase in rates of approximately 3.5 percent for the typical residential customer. All these rate increases became effective August 1, 2003. The BGS fixed price portion will be adjusted again to reflect the 2004 auction results.

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<sup>10</sup>Presentation by Commissioner Frederick F. Butler, "Acquiring Electric Supply: An Overview of the New Jersey Basic Generation Service Auction Solicitation Process," given at *Post 2006 Symposium*, Chicago, IL, April 29, 2004.

## Pennsylvania

Pennsylvania had, at one time, the most active retail access program in the country. In early 2000, PECO Energy alone, then the most active service area in the state (and the country), had 29 offers being made to residential customers—about 20 of which were below the price-to-compare. Every service area in the state had at least two offers to residential customers that were below the price-to-compare. This changed dramatically by mid-2001, when many competitive suppliers reduced their offerings to customers or left the market entirely.

Table II.7 shows that in May 2003, the entire state had only one offer below the price-to-compare and none in 2004. In May 2002, the state had three such offers, all in PECO Energy's service territory. The number of competitive suppliers in each company's territory remained about the same and, with the exception of PECO Energy's area, the total number of offers from these suppliers also remained about the same. There offers were overwhelmingly for "green power" where at least some portion of the generation uses a renewable energy source. Of the 34 total offers in the state from competitive suppliers in July 2004, all but three had some portion of renewable resources use (the three non-renewable offers were all in PECO Energy's territory).

The 2003 Performance Review summarized an analysis by the PJM MMU that concluded that there was an exercise of market power in PJM's capacity credit markets during the first quarter of 2001,<sup>11</sup> and included additional explanation and the findings from an investigation by the Pennsylvania Public Utility Commission and the Pennsylvania Attorney General. The capacity credit market's problems combined with the energy market prices in early 2001 was clearly a significant factor that caused the drop-off in retail market activity in Pennsylvania and other PJM states. The highest "shopping credit" or price-to-compare for generation service in Pennsylvania at that time was in PECO Energy's territory, at 5.67 cents/kWh.<sup>12</sup> When energy prices reached over

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<sup>11</sup>PJM Interconnection, L.L.C., Market Monitoring Unit, "Report to the Pennsylvania Public Utility Commission, Capacity Market Questions," November 2001.

<sup>12</sup>Current annual average price-to-compare for regular residential service.

\$50/MWh, as it averaged during December of 2000 and again in August of 2001, adding \$10/MWh for capacity<sup>13</sup> would place the total cost over \$60/MWh or 6 cents/kWh, well above the fixed PECO Energy price-to-compare at that time and about the level of the 2004 price-to-compare (see Table II.7 for the 2004 price-to-compare by company). 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 of 2001, 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. The retail markets have not returned to those pre-2001 levels of activity.

Figures II.5, II.6, and II.7 plot the customer switching activity for Pennsylvania back to the first quarter of retail access in the state for residential, commercial, and industrial customers, respectively. The decrease that occurred in 2001 in retail market activity can be seen in all three customer groups. Residential switching continues to decline or remain flat, with all but Duquesne Light and PECO Energy now below one percent of customers with an alternative supplier.

There have been two assignments of residential customers in the PECO Energy area. The affect of the first assignment can be seen in the April 2001 percentage. While it drifted downward after the initial assignment, it dropped considerably in 2002 when the main supplier returned its customers back to PECO Energy (180,000 customers of NewPower, an affiliate of Enron, ceased to be a competitive supplier and transferred its customers back to PECO Energy in April 2002). The second assignment of residential customers in PECO Energy's territory can be seen in the January 2004 percentage, when it jumped back to about 20 percent of customers. It declined

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<sup>13</sup>The PJM Market Monitoring Unit in its report on the 2000 market issued in 2001, states 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.”

somewhat in April 2004, down to 17.7 percent. Without the assigned customers, PECO Energy residential customer switching for April was four percent.

**Table II.7.** Competitive offer summary for Pennsylvania residential customers.\*

Utility	2004 Price-to-Compare (¢/kWh)	Number of Competitive Suppliers		Total Number of Offers from Competitive Suppliers		Number of Offers Below the Price-to-Compare	
		May 2003	July 2004	May 2003	July 2004	May 2003	July 2004
<b>Allegheny Power</b>	3.871	2	1	3	2	0	0
<b>Duquesne Light</b>	5.83	3	2	4	3	1	0
<b>Met Ed</b>	4.588	2	2	3	3	0	0
<b>PECO Energy**</b>	6.17	6	6	7	14	0	0
<b>Penelec</b>	4.592	2	2	3	3	0	0
<b>Penn Power</b>	5.273 <sup>†</sup>	2	2	3	3	0	0
<b>PPL Utilities</b>	4.84	2	2	3	3	0	0
<b>UGI</b>	5.803 <sup>†</sup>	2	2	3	3	0	0

\*For Regular Residential Service.

\*\*Does not include the “Market Share Threshold Program Service” (MST), which for 2004 is priced at 0.09 cents/kWh less than PECO Energy’s Price-to-compare, or at about a 1-1/2 percent discount. This is only available to preselected MST customers, not available to new customers.

†Price for 1,000 kWh, actual price depends on usage.

Source: Pennsylvania Office of Consumer Advocate, May 2003 and July 2004.

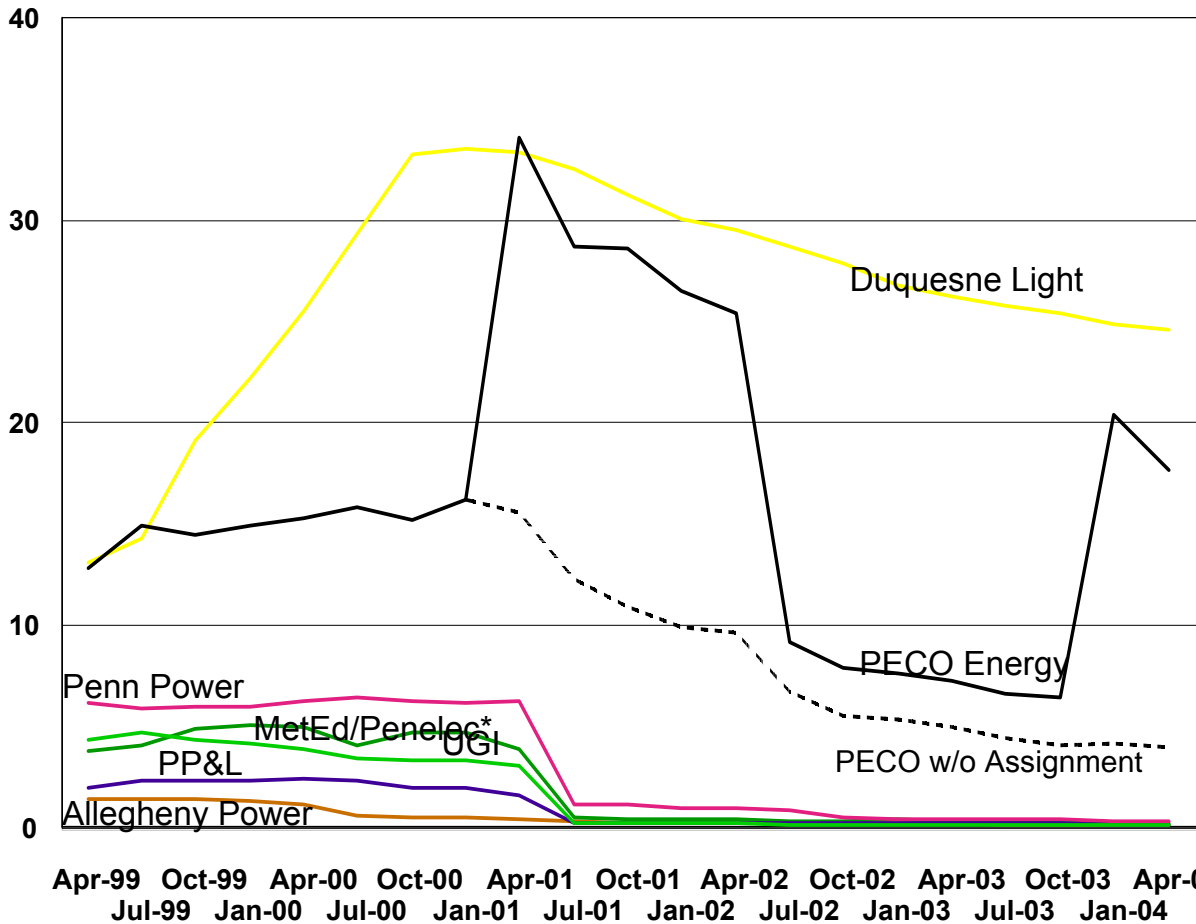
With commercial customers (Figure II.6), all areas, again except Duquesne Light and PECO Energy, are at or below one percent – PPL is reported at one percent and Allegheny Power, Met Ed/Penelec, Penn Power, and UGI are reported at 0.1 percent. Duquesne Light is at just above 20 percent and PECO Energy, with the assignment of its commercial customers, is at 38.5 percent. Without the customer assignment, PECO Energy commercial customer switching drops to 9.5 percent.

Industrial customer switching in Pennsylvania (Figure II.7), for all areas, except Duquesne Light, are well below five percent. Nearly 40 percent of the customers in Duquesne Light's territory are with an alternative supplier.

Figure II.8 shows the percent of load served by alternative suppliers in the state in April 2004. Only Duquesne Light and PECO Energy have a sizable percentage of their total load served by alternative suppliers (with Duquesne Light at about one-third of its total load). Also, Met Ed/Penelec industrial load is above 20 percent.

Figure II.9 shows the decline in customer switching in the state in terms of total load. The peak was reached in April of 2000, at 8,320 MW, fell to 5,509 MW in July 2000, then fell again to 2,039 MW in July 2001. Since then, total load served by an alternative supplier has climbed back to over 3,000 MW in 2004 (2,326 MW in April 2004 without the PECO Energy assigned residential and commercial load). This is about 10 percent of the state's total load.

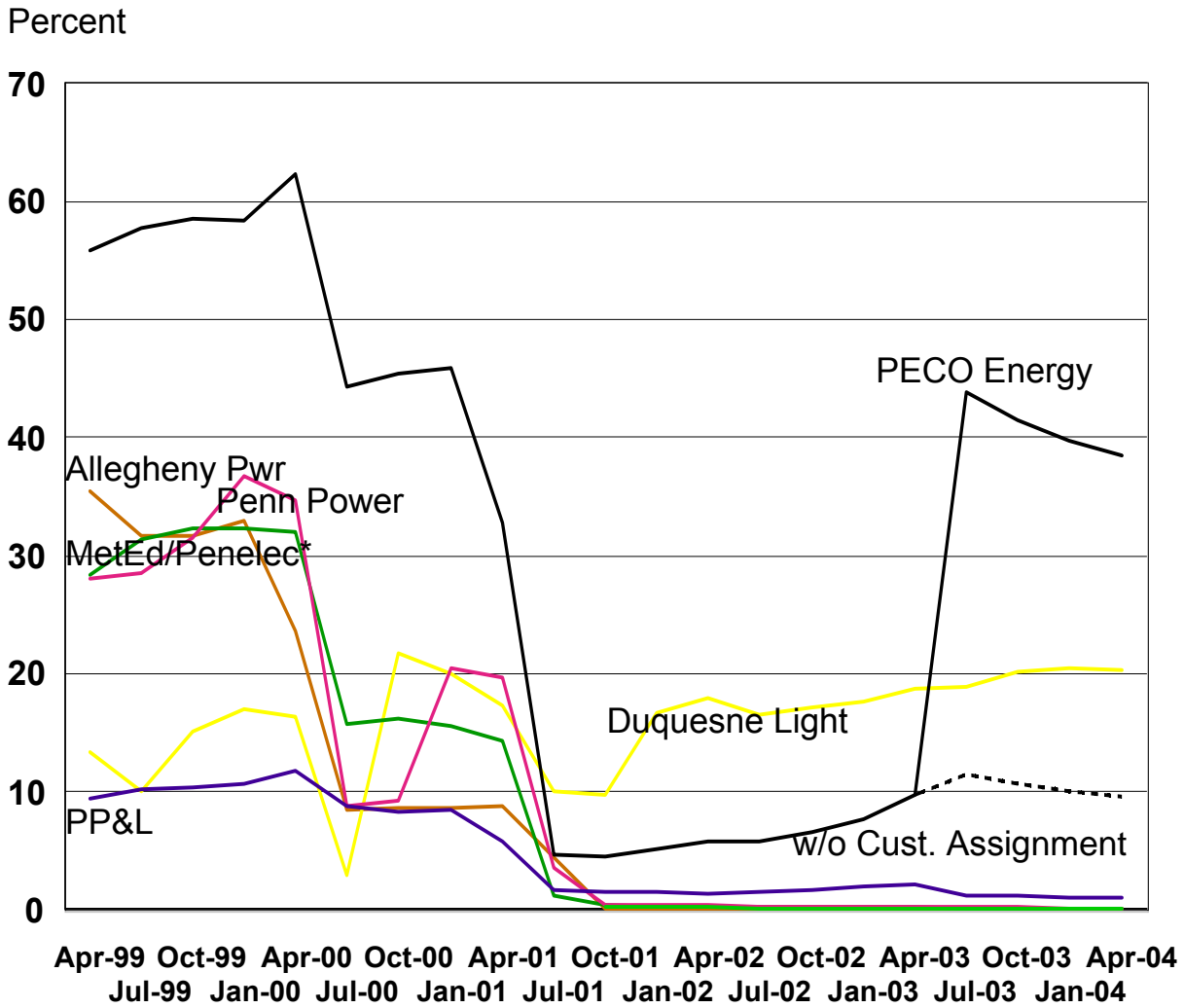
Percent



\*MetEd and Penelec were formerly part of GPU.  
 Data Source: Pennsylvania Office of Consumer Advocate

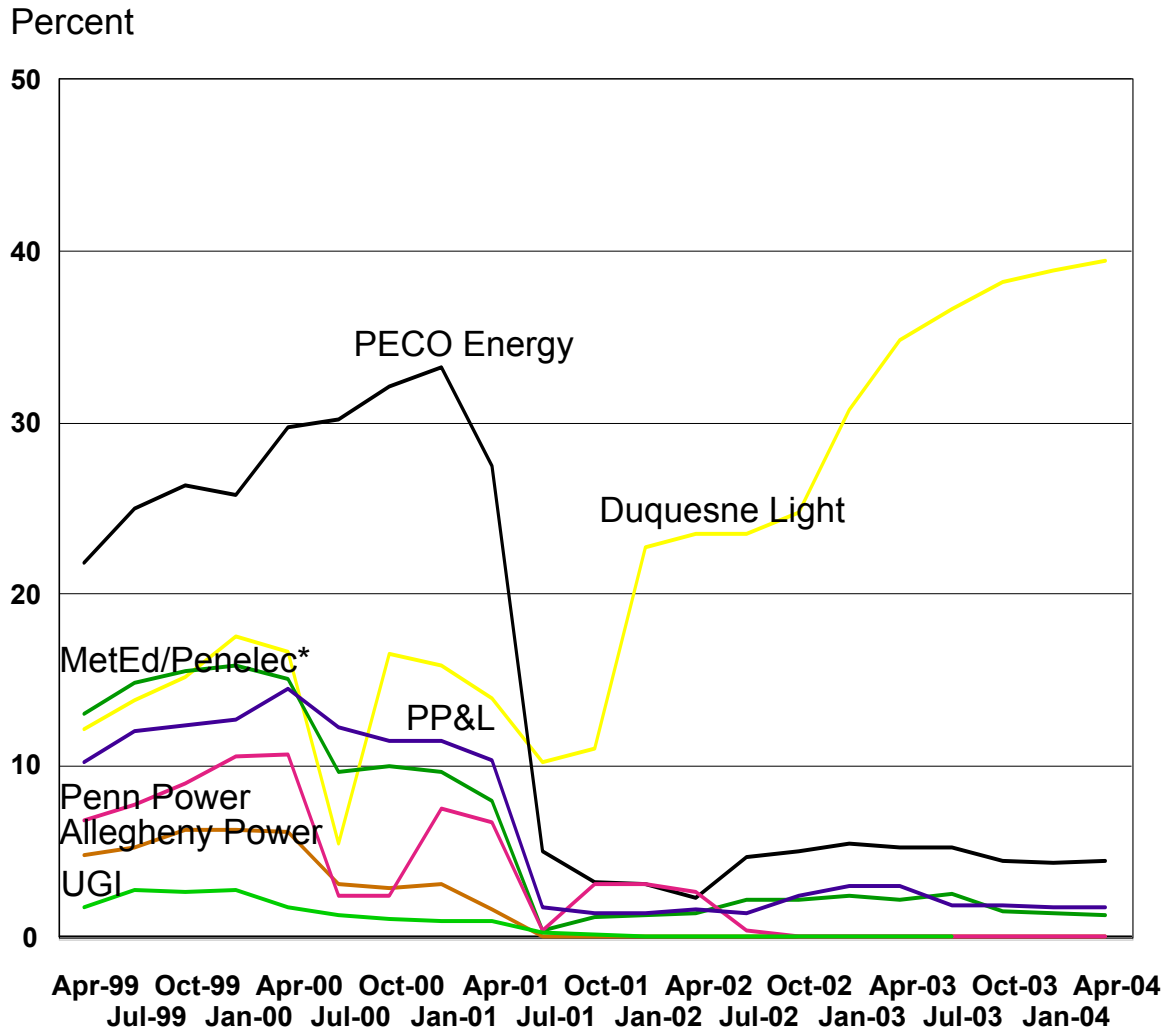
**Figure II.5.** Percent of residential customers served by an alternative supplier in Pennsylvania.





\*MetEd and Penelec were formerly part of GPU.  
 Data Source: Pennsylvania Office of Consumer Advocate

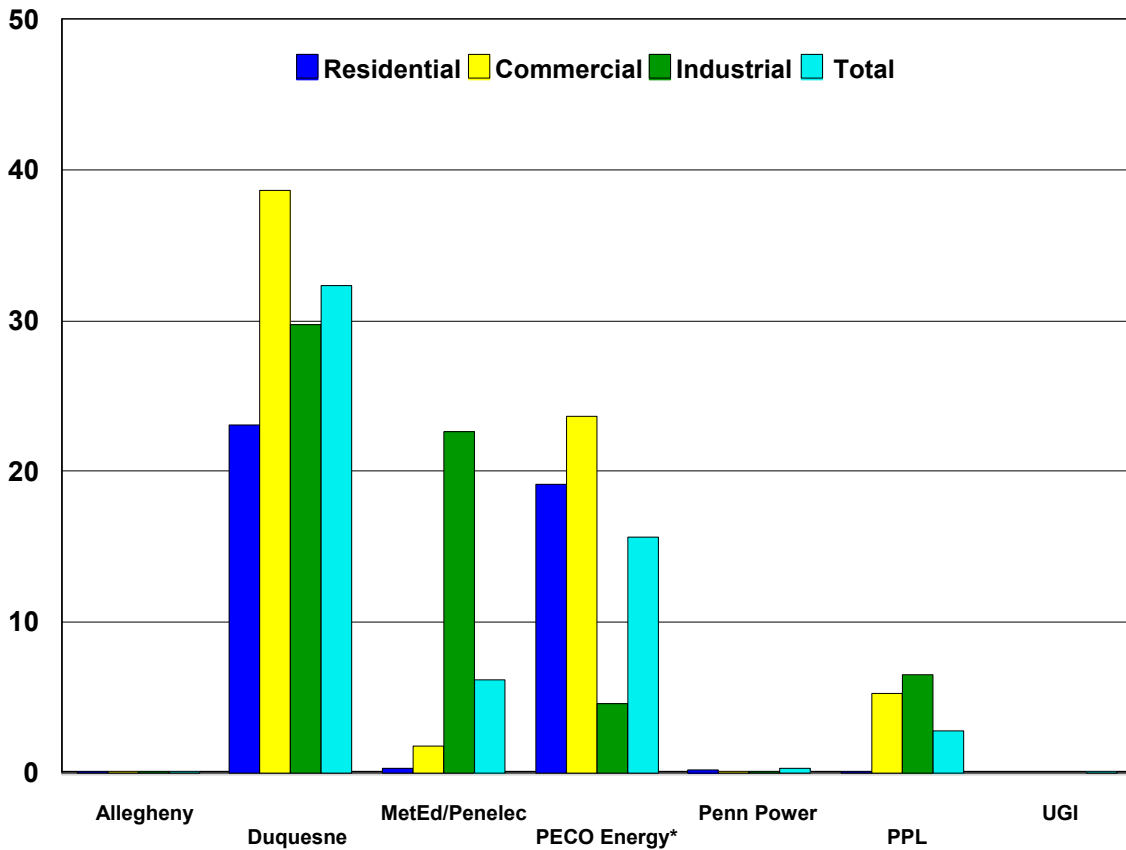
**Figure II.6.** Percent of commercial customers served by alternative suppliers in Pennsylvania.



\*MetEd and Penelec were formerly part of GPU.  
 Data Source: Pennsylvania Office of Consumer Advocate

**Figure II.7.** Percent of industrial customers served by alternative suppliers in Pennsylvania.

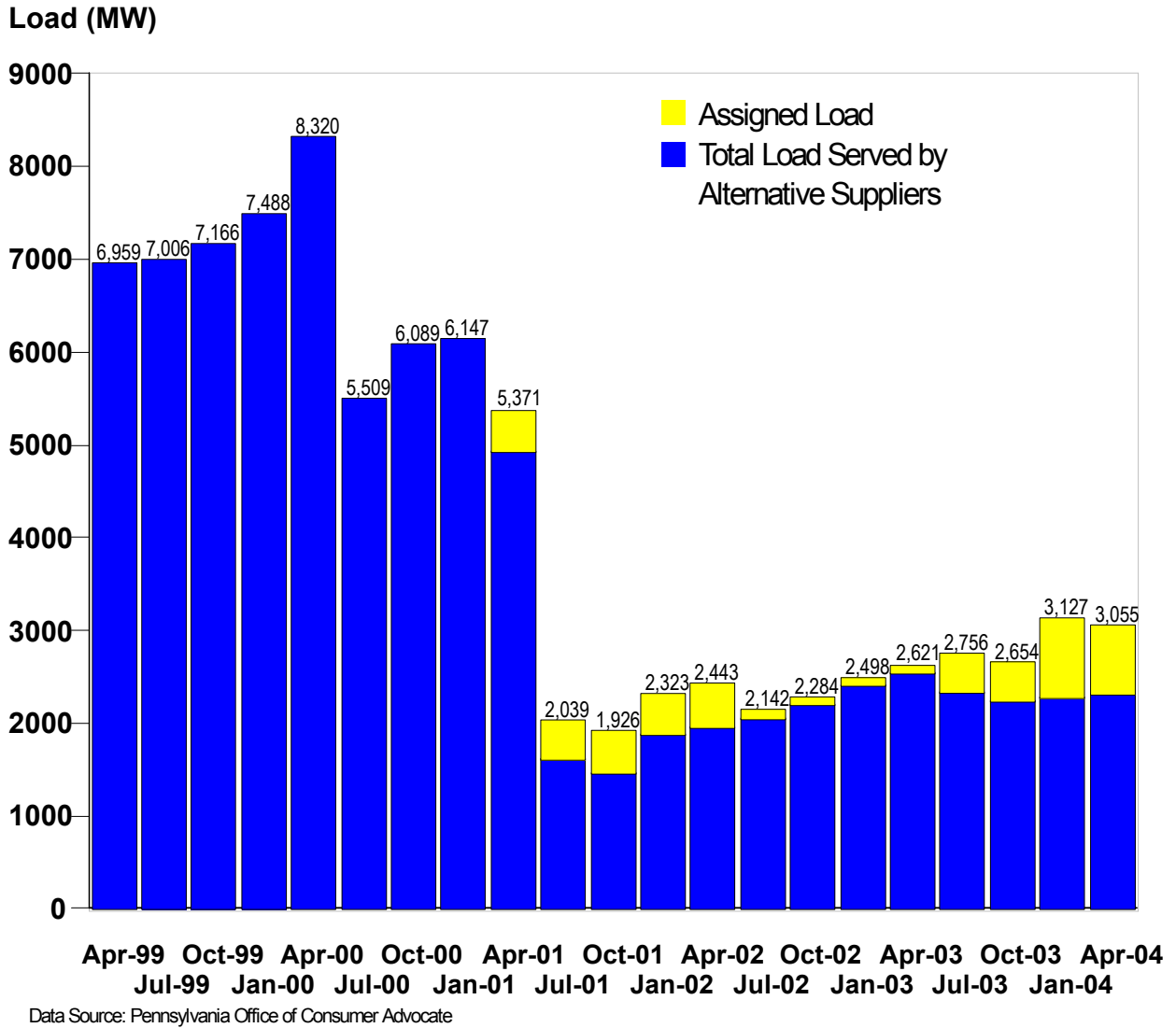
Percent



\*PECO numbers include 14.7% of residential customer load and 12.9% of commercial customer load assigned to "Market Share Threshold Program."

Data Source: Pennsylvania Office of Consumer Advocate

**Figure II.8.** Percent of customer load served by alternative suppliers in Pennsylvania, by utility company in April 2004.



**Figure II.9.** Total customer load served by alternative suppliers in Pennsylvania.

## **Section III New England**

### **Wholesale Market and ISO New England**

The New England Power Pool (NEPOOL) was created in 1971 from the integration of most of New England's utilities and municipal systems. This includes all of Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont and the southern portion of Maine.<sup>1</sup> NEPOOL was created primarily to enhance the region's system reliability in response to the northeast's 1965 blackout. After FERC Order 888 was passed, that mandated transmission open access, NEPOOL chose to contract with ISO New England, Inc. to meet the operational and organizational structural requirements of an ISO under the FERC Order. ISO New England was created and in 1997 approved by FERC to operate the six-state New England region's bulk electric power system and wholesale electricity markets. In March 2004, FERC conditionally approved ISO New England as a Regional Transmission Organization (RTO). Currently, NEPOOL's responsibilities include the Open Access Transmission Tariff (OATT) and the market rules for the exchange of wholesale power. ISO New England currently administers OATT, and operates the transmission system, the dispatch of generation, and the electricity markets.<sup>2</sup>

ISO New England has interconnecting transmission lines connecting it to New York State and Quebec and New Brunswick in Canada. These lines are for the sale and purchase of electricity between the regions and for reliability purposes. From ISO

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<sup>1</sup>Northern Maine is not part of NEPOOL and is not directly connected to the rest of Maine and New England. However, northern Maine is electrically connected through transmission lines through New Brunswick that are part of the transmission system that interconnects the northeastern U.S. and central and eastern Canada.

<sup>2</sup>This description of responsibilities for NEPOOL and ISO New England is from 106 FERC ¶61, 280, "Order Granting RTO Status Subject to Fulfillment of Requirements and Establishing Hearing and Settlement Judge Procedures," March 24, 2004.

New England's description, the power system and wholesale market serves about 6.5 million customers in an area with a population of 14 million people. The total energy market value is \$7 billion, with \$1.8 billion cleared in the spot market. There are over 350 generating units and over 8,000 miles of high-voltage transmission lines. New England system is a summer peaking system with peak demand in summer typically between 19,000 MW and 23,000 MW and winter peak demand between 17,000 MW and 19,000 MW. On August 14, 2002 a peak demand of 25,348 MW was reached, which is the current record peak demand for the region. The normal weather summer peak has increased by 20 percent over the last ten years.

ISO New England began managing the region's restructured wholesale power markets in May of 1999. In March 2003, the region began implementing its own version of a wholesale Standard Market Design. This includes using Locational Marginal Pricing (LMP) for transmission congestion management, day-ahead and real-time energy markets, and using monthly and long-term Financial Transmission Right (FTR) auctions to allow market participants to hedge against the possibility of paying transmission congestion charges under LMP in the day-ahead market.

The New England power market trades about 75 percent of its electricity under bilateral contracts and 25 percent in the real-time market.

The ISO currently has about 31,000 MW of total capacity and maintains an operating reserve margin of about 1,700 MW. The region is expecting to add approximately 3,500 MWs within the next year (as of May 2003). The region's electricity supply has increased by about 40 percent within the past five years.

### Dependance on Natural Gas

According to ISO New England, approximately 29 percent of the total megawatt hours produced in the region in 2002 was from natural gas generators, this was up considerably from 13 percent in 2000. Nuclear and coal generated 26.6 percent and 12.3 percent, respectively, in 2002.

This increasing use and reliance on natural gas for power generation is causing concern in the region. ISO New England issued a White Paper that examined current

and future use of natural gas for power generation and natural gas supply availability in the region.<sup>3</sup> The study notes that the recent power plant building boom in the region is expecting to add nearly 10,700 MW of new capacity between 1998 and 2005—all of it natural gas-fired capacity. It is expected that 41 percent of New England’s total electricity production will be gas-fired in 2003 and could reach 49 percent by 2010. The study notes that, except for Texas,<sup>4</sup> “New England is by far the most dependent region in North America on natural gas for power generation.” In addition, because of insufficient pipeline capacity in the region, studies by ISO New England indicate that approximately 2,800 MW to 3,900 MW of gas-fired generation would be unserved by pipelines during a peak winter day as soon as by the winter of 2004/2005. This is due to the coincident natural gas and electric generation requirements during the heating season.

This problem is particularly acute in the Boston area “load pocket.” The Boston subarea is expected to have 65 percent of its electricity generated by natural gas in 2003 and is forecasted to increase to 80 percent by 2010. If a single power plant that is critical to the sub-area’s electric supply, the Salem Harbor plant, is converted to natural gas, that subarea’s electricity generated with natural gas could rise to 94 percent. Salem Harbor is a 745 MW coal- and residual fuel oil-fired power plant with four units located about 15 miles north of Boston; it accounts for about 21 and 23 percent of the Boston area’s current winter and summer generating capacity, respectively. Because of its fuel use and location, it is subject to state and federal environmental regulations for nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury emissions. Compliance options include switching to natural gas use or retiring the plant. Because transmission

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<sup>3</sup>ISO New England Inc., “Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket,” prepared by Levitan & Associates, Inc., July 1, 2003.

<sup>4</sup>Texas (ERCOT region) is 44 percent natural gas-fired generated, according to Energy Information Administration numbers presented in Table 3 of the White Paper on page 13. They also note that Texas is in a region that has ready and ample natural gas supplies, while New England must rely on supply basins that are between 750 to 4,000 miles away.

constraints limit the amount of power that can be sent from outside the subarea, either of these options would have a major impact on the subarea's fuel diversity and supply resources.

### Blackout of 2003

According to ISO New England, the blackout of August 14, 2003 created the system's "most challenging conditions in more than 30 years of operation."<sup>5</sup> However, the impact was limited to small areas in Springfield and the Berkshires Massachusetts and in southwest Connecticut and northwest Vermont. The ISO believes that New England escaped further impact because of automatic relays that shut down its links with New York, system operators who were able to stabilize the system, adequate generation within the system to be self-sufficient once isolated from the rest of the Eastern Interconnection, and close coordination between the ISO and utilities to restore power to the effected areas. While the ISO believes it generally preformed well during the crisis, they made policy recommendations to ensure future reliability and make it less likely that there will be a reoccurrence of the blackout. There specific recommendations are similar to the U.S. - Canada Power System Outage Task Force discussed in Section I. These include national and regional standards, restoration plans, and further analysis.

### The January 2004 "Cold Snap"

Another significant challenge that the ISO recently faced occurred during severe cold temperatures that affected the region January 14 through 16, 2004. ISO New England also issued a report examining this event in detail.<sup>6</sup> The severe weather caused unprecedented winter demand on both the electricity and natural gas systems.

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<sup>5</sup>ISO New England, "Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout," February 2004.

<sup>6</sup>ISO New England Inc., Market Monitoring Department, "Interim Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 'Cold Snap,'" May 10, 2004.



New record winter peaks were set on January 14 and reset again the next day at 22,817 MW. According to the ISO, at the peak hour on January 14, the hourly real-time price rose to nearly \$1,000 per MWh (there is a \$1,000 per MWh bid cap) and day-ahead natural gas prices in the New England system increased to nearly ten times their normal levels. The report concluded that the region's electricity system performed well and the ISO was able to avoid supply interruption despite record winter peak electricity demand and unexpected generator outages. They also found no evidence of anti-competitive behavior by generators. They did find however, that the "Cold Snap" of January 2004 did highlight vulnerabilities of the New England power system, especially in the natural gas pipeline network's capacity limitations.

Echoing the concerns raised in the July 2003 Levitan & Associates report done for the ISO, mentioned above, the report noted the region's dependence on natural gas for electric power generation and how it can cause problems during periods of extremely cold temperatures. They point out that most of the new generation capacity added in New England since 1990 is fueled by natural gas and that currently over 30 percent of winter capacity consists of gas-only units and another 20 percent is gas-capable dual-fuel units. On January 14, there was 8,927 MW of unavailable capacity, gas-capable units were 81 percent (7,238 MW) of that total unavailable capacity and the largest category of outages by fuel type.

Their finding of no evidence of anti-competitive behavior by generators is based on analyses conducted by the ISO's own Market Monitoring Department. They examine whether there was any economic or physical withholding and found no evidence of anti-competitive behavior. Price offers from gas-fired units may have increased sharply, they argued, but this was consistent with gas market conditions at the time and was consistent with expected supplier market behavior under the circumstances. Using several tools to analyze market behavior during this period, including pivotal supplier and competitive benchmark analyses (discussed below), they found no instances of improper or anti-competitive behavior on the part of suppliers during this cold weather period.

FERC's Office of Market Oversight and Investigations (OMOI) also conducted an investigation of the January events and came to similar conclusions.<sup>7</sup> In this case, they examined both the electricity and natural gas markets. They believed that the natural gas markets in the region responded well under the circumstances and found no manipulation in gas market trading (natural gas spot prices spiked on January 15th, averaging \$63 and a few trades as high as \$75/MMBtu). On the electric side, they concluded that electric markets had no service interruptions, customers were largely protected from the price spikes in spot power market due to forward contracting (the real-time market price peaked at \$920 per MWh on Jan 14, for one hour), natural gas sales by generators complied with market rules, the price spike were not the result of physical or economic withholding or manipulation, and there was no misbehavior or exercise of market power.<sup>8</sup> They also noted that plant mechanical and fuel-related outages reached 8,927 MW, with 81 percent being gas-capable units. OMOI also noted that 36 percent of the outages were fuel related and that half of fuel outages involved generators selling firm natural gas into the spot market. They note that natural gas still managed to serve 27 percent of the load.

The Connecticut Attorney General issued a press release<sup>9</sup> stating that he filed comments with ISO New England, disputing the ISO report's conclusion that no significant flaws in the region's power system were involved the cold snap. The Attorney General stated:

Most notably, ISO-NE should reconsider its preliminary conclusion that 'New England's electricity system performed well in most respects.' To the contrary, the evidence in the interim report demonstrates that the market

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<sup>7</sup>William F. Hederman, Office of Market Oversight and Investigations, Federal Energy Regulatory Commission, "Investigation of New England Gas-Electric Market Events January 13-16, 2004," presentation at the New England Conference of Public Utilities Commissioners, Brewster, MA, May 24, 2004.

<sup>8</sup>Conclusions from Hederman, slide 3.

<sup>9</sup>Connecticut Attorney General's Office, "Attorney General Disputes Findings of ISO-NE Study On Near Blackout During January Cold Snap," Press Release, July 6, 2004.

rules in place during the cold snap and ISO-NE's administration of those rules were not adequate to protect Connecticut's electricity consumers from the threat of rolling blackouts on the coldest night of the year and, in fact, imperiled the health and safety of millions of New England residents. During such times of extreme cold, the availability of reliable electricity is, first and foremost, a matter of public safety.

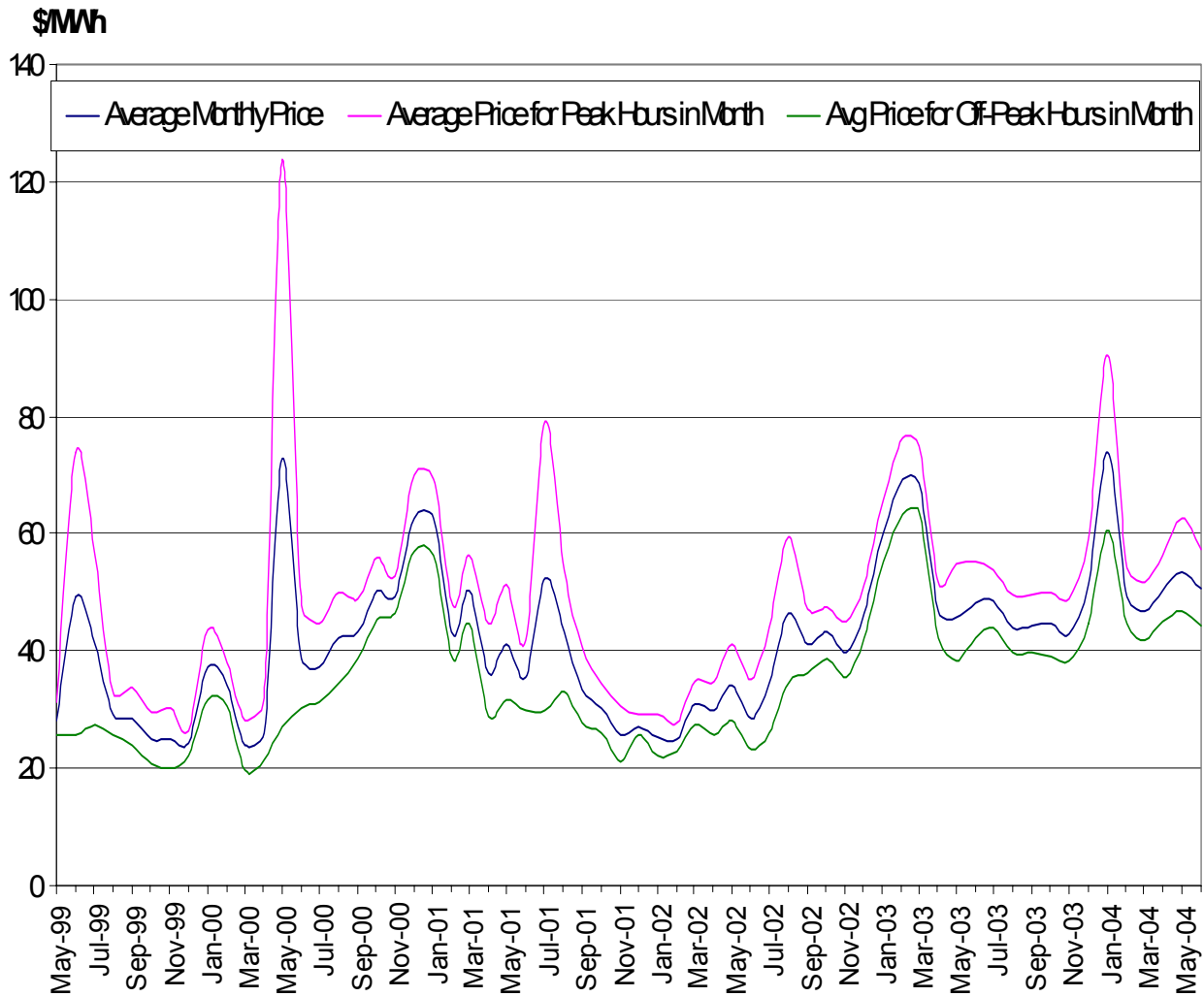
Among several criticisms of the ISO report's findings and methods, the Attorney General pointed to the fact that power suppliers shut down their plants and sold their natural gas into the spot market rather than use it to generate electricity at a critical time. In addition, the Attorney General believed that the ISO failed "to determine if generators took advantage of the cold snap to manipulate the wholesale electricity market or engage in anti-competitive behavior."

#### New England Wholesale Prices

ISO New England's monthly average prices are charted in Figure III.1. This is the monthly average, on-peak monthly average, and off-peak monthly average prices for May 1999 through May 2004.<sup>10</sup> The impact on prices from the hot weather in late July and early August of 2001 can be seen and, as seen with most other power markets, the impact from the higher natural gas prices in early 2003 and during the "cold snap" of January 2004. The monthly averages show a significant impact in January 2004, increasing monthly averages to the highest levels since 2000. As seen in other wholesale power markets, the highest annual peaks of the last two years have occurred in the winter months.

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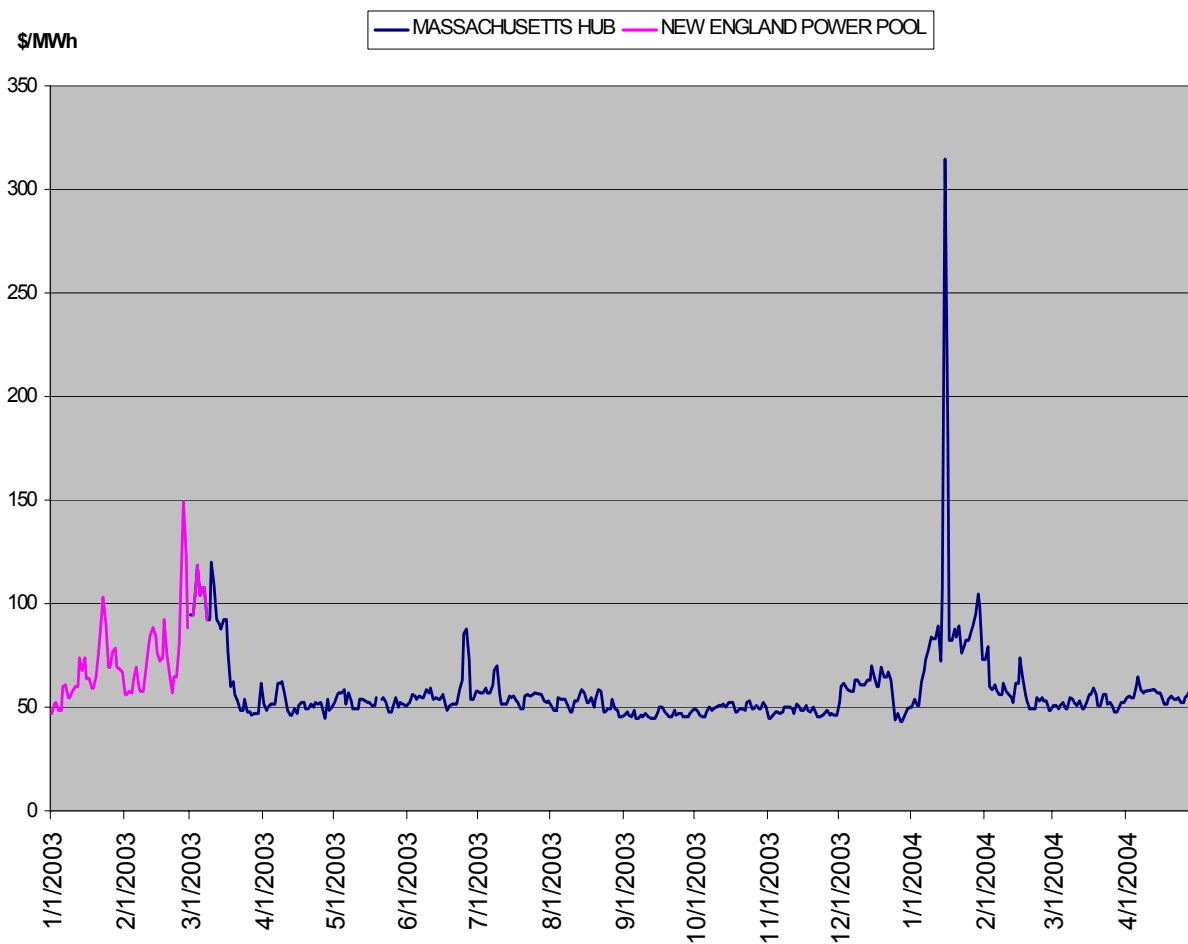
<sup>10</sup>For May 1999 through February 2003, prices are the monthly average clearing price, monthly average on-peak price, and monthly average off-peak price. For March 2003 through May 2004, the period of ISO New England's Standard Market Design, prices are the average real-time LMP (the average hourly real-time hub or zone LMP for the month), on-peak LMP (the average real-time hub or zone LMP for peak hours in the month, where peak hours are hours ending 8:00 AM to 11:00 PM Monday through Friday excluding holidays), and off-peak LMP (average real time hub or zone LMP for the off-peak hours in the month).



**Figure III.1.** Average monthly, average monthly peak, and average monthly off-peak prices in ISO New England, May 1999 through May 2004.

Source: ISO New England, June 2003 and July 2004.

Figure III.2 plots wholesale prices for deliveries into the New England Power Exchange (operated by ISO New England) for January 1, 2003 to March 10, 2003 and for the Massachusetts Hub price (from Platts, *Megawatt Daily*), located in central Massachusetts, for March 1, 2003 through April 30, 2004. This is a daily volume weighted average index of peak hour prices (in dollars per MWh). Again, the impact from natural gas prices can be seen in this daily index in early 2003 and 2004. The peak for January 2004 was on January 15, 2004 (during the “cold snap”), at \$315 per MWh. The index stayed above \$70 from January 7 through February 2, 2004.



**Figure III.2.** New England wholesale volume weighted average index, January 2003 through April 2004 (\$/MWh).  
Source: Platts, *Megawatt Daily*, 2003 and 2004.

## Market Performance Analyses

Last year's Performance Review summarized a study of the New England ISO market by Bushnell and Saravia<sup>11</sup> that used a "competitive benchmark analysis." This competitive benchmark is the estimated price that would result if all firms acted as price-taking firms—that is, no firm exercises market power.<sup>12</sup> (The basis for examining wholesale market performance is discussed in Section I.) The study examined the period of May 1999 through September 2001. The results of the Lerner index estimation are summarized in Figure III.3. The Lerner index estimation uses their benchmark estimation with ISO New England's Energy Clearing Prices.

Bushnell and Saravia also graphed the relationship between demand and the Lerner index for May to September for 1999, 2000, and 2001, which is shown in Figure III.4. The graph is relatively flat for moderate levels of demand, indicating that the Lerner index (and market power markup) is low. However, at higher levels of demand, the index rises quickly and reaches values and reaches 20 percent just before 12,000 MW (for the 2001 estimate).<sup>13</sup>

The authors pronounce the overall results "encouraging," but caution:

The results described above occur in a market with many layers of continued regulation. The vertical integration of some suppliers and the transition contracts imposed on others provide a powerful mitigating influence on the incentives of these firms to exercise market power. Any new contracts that replace those imposed during the transition will be set at terms determined by market conditions, rather than regulatory

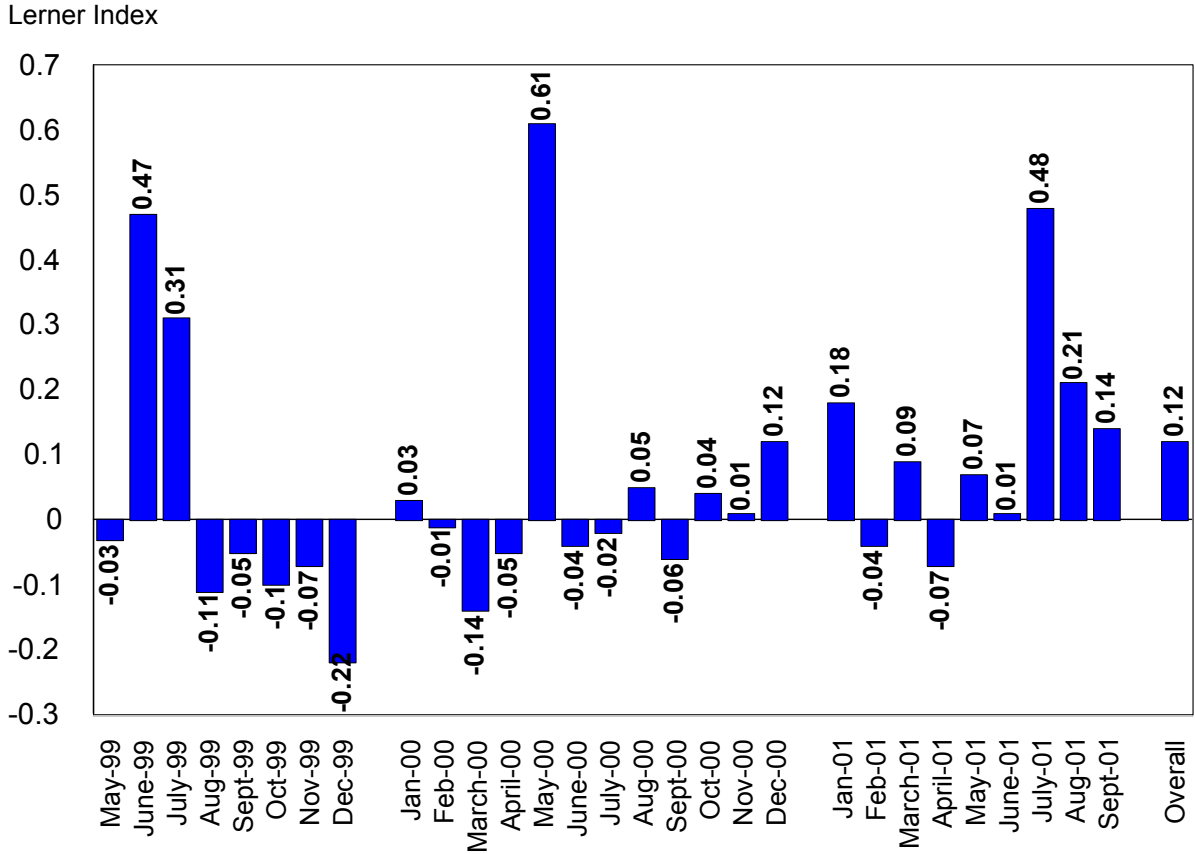
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<sup>11</sup>James Bushnell and Celeste Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," Center for the Study of Energy Markets (CSEM WP-101), University of California Energy Institute, Berkeley, California, May 2002.

<sup>12</sup>This is based on an estimated incremental cost of the cheapest unit that is not needed to serve demand in a given hour.

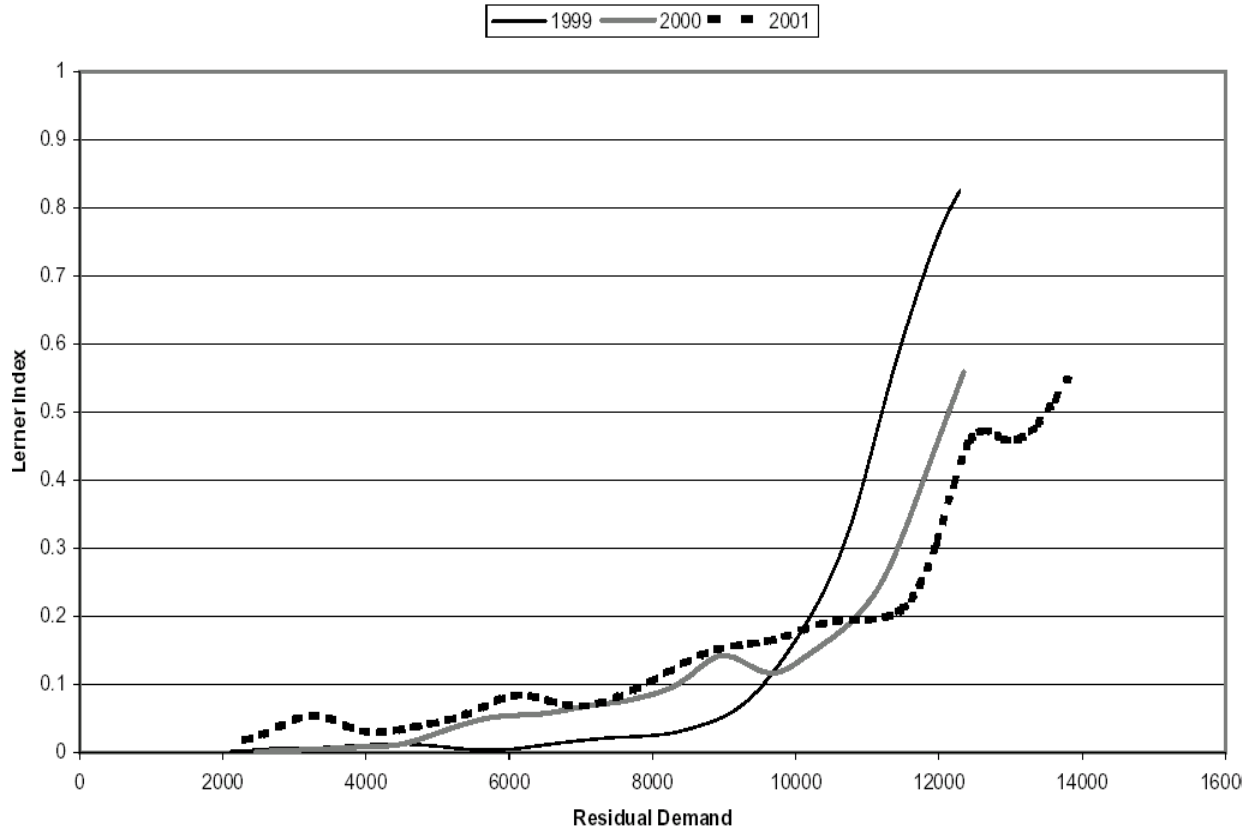
<sup>13</sup>A similar graph that compares California, New England, and PJM Lerner Indices is in Section II of the 2003 Performance Review.

proceedings. The pending expiration of transition periods and potential consolidation of supply portfolios will reverse this effect.<sup>14</sup>



**Figure III.3.** Monthly Lerner Index for New England electricity market, May 1999 to September 2001.  
 Source: Bushnell and Saravia, “An Empirical Assessment of the Competitiveness of the New England Electricity Market,” May 2002.

<sup>14</sup>Bushnell and Saravia, p. 21.



**Figure III.4.** The relationship between the level of demand and the Lerner index for New England.

Source: Bushnell and Saravia, “An Empirical Assessment of the Competitiveness of the New England Electricity Market,” May 2002.

ISO New England conducted its own annual assessment of the performance of the region’s wholesale electricity markets.<sup>15</sup> The ISO’s Market Monitoring Department also developed its own competitive benchmark analysis based on, with some

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<sup>15</sup>ISO New England, 2003 Annual Markets Report, 2004. A 2002 analysis by the Independent Market Advisor to ISO New England, David B. Patton, Robert A. Sinclair, and Pallas M. LeeVanSchaick, “Competitive Assessment of the Energy Market in New England,” Independent Market Advisor to ISO New England, Potomac Economics, Ltd., May 2002, was summarized in last year’s Performance Review.



modifications, Bushnell and Saravia methodology. Their benchmark is similarly an estimate of the market price if market participants operated in a perfectly competitive market. The estimated benchmark price is based on production costs, unit availability, and net imports. This benchmark and the market prices are again used to calculate a Lerner index. Their quantity-weighted Lerner index is 11 percent for 2002 and nine percent for 2003. The ISO concludes that this indicates “that the New England markets continue to be workably competitive.”

While the ISO’s estimates are just below Bushnell and Saravia overall estimate of 12 percent, as Figure III.3 shows, there is considerable monthly variation in the Lerner index. And Figure III.4 shows that there is considerable variation as load increases. The ISO’s report does not report any monthly or load-level estimates. While the estimation methodology may be similar, the reporting of the results were not.

The ISO’s annual Lerner index estimates alone do not justify the firm conclusion they reach about the wholesale market’s competitiveness. They do conduct other tests that characterize the market’s structure. They use the Herfindahl-Hirschman Index (HHI, which is calculated as the sum of the squared market shares) to measure market concentration. Based on the Department of Justice’s *Horizontal Merger Guidelines*, which is often used to interpret HHI results, a market is considered “highly concentrated” when the HHI is greater than 1800, “unconcentrated” below 1000, and “moderately concentrated” in the “gray area” between 1000 to 1800. HHI is usually used as a screening tools to decide if further investigation is necessary—not for a definitive answer on competitiveness or market power.

Overall, for the entire New England market, the ISO’s HHI calculation shows a considerable drop in the index from over 1500 in 1999 to about 600 in late 2003. When broken down by sub-region, the ISO’s 2003 HHI numbers show that five sub-regions have HHIs greater than 2000, two are just at or over 3000, and one, the Boston area, is greater than 5000.

The ISO also looks at market share, and note that the largest generator reduced its portfolio by 1,100 MW during 2003. They do not report the actual percentage shares of the generation in the region. One generator has nearly 4,000 MWs in December

2003, which appears to be approximately 19 percent to 20 percent of the generation of the ten largest generators (estimated from figure in the ISO's report).

The ISO also plotted outages and demand levels and note that as demand levels increase, there were fewer plant outages. They believe this suggests that markets are providing an incentive to make units available when most needed and that outages are scheduled by the ISO appropriately. They do not draw any conclusion on possible withholding or strategic behavior by suppliers from the observed negative correlation (as was done in the New York analysis discussed in section IV).

They also conduct a residual supply index (also called a pivotal supplier index) that measures the percentage of load that can be met without the largest supplier.<sup>16</sup> If the index is less than 100 percent, at least a portion of the largest supplier's capacity is needed to meet total demand and that supplier is "pivotal." The ISO's results show that the index was less than 100 percent only for 18 hours in 2003—all these hours occurred in June and July—and below 110 percent for only 161 hours—mostly in April, June, July and August (months it was above 20 hours). The 161 hours is less than two percent of the hours in a year. This index provides some indication of a supplier's ability to control the market price when there is a "pivotal" supplier. For this reason, this measure is a useful screening device for further analysis. However, it will not indicate whether a supplier actually exercised their market power and raised prices or the extent to which they actually raised prices. This test also cannot indicate the extent that strategies used by non-pivotal suppliers may be effective in influencing the market price.

Finally, the ISO makes a comparison of what a new generating unit's revenue requirement needs to be to cover costs of the unit and a competitive return on the investment with the revenues obtained from the energy, capacity, and ancillary services markets. Sufficient market revenues should indicate that new entry is profitable, while insufficient revenues would indicate that entry is being discouraged and could lead to higher prices in the future. The ISO's estimation for hypothetical generators in New England in 2003 indicates that the plants would not be able to recover annual fixed

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<sup>16</sup>That is,  $(\text{total supply capacity} - \text{largest supplier capacity}) \div \text{total demand}$ .

costs plus a return on investment from energy market revenues alone. They conclude that

it appears that at 2003 electric energy prices and fuel costs, the hypothetical generators' net revenues were lower than the amount needed to cover a new entrant's fixed costs and competitive rate of return on investment. This observation is consistent with relatively robust reserve margins, the lack of announcements of new projects, few units in the early stages of construction, and the cancellation of some new generation projects.<sup>17</sup>

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<sup>17</sup>ISO New England, 2003 Annual Markets Report, p. 60.

## **Retail Markets**

Five of the six New England states have retail access, Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island, and were among the first states to pass restructuring legislation and implement retail access. Maine and Massachusetts are updated below.

### Maine

Maine's Restructuring Act required complete divestiture of transmission and distribution (T&D) utilities' generation assets. Maine chose to have the T&D utilities supply standard offer generation service to retail customers through a competitive process conducted by the Maine Public Utilities Commission. This has been done through a competitive bidding process or, if bids are insufficient or unacceptable to the Commission, through wholesale contracts. The T&D utilities themselves cannot participate in the bidding to become the standard offer provider and affiliates of the T&D utilities cannot provide more than 20 percent of the standard offer service in the affiliated T&D utility's service territory. Maine has one type of default service, the standard offer service, for each of the three primary retail customer classes.<sup>18</sup> This standard offer serves all customers in the class that are not receiving power from a competitively-obtained supplier.

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<sup>18</sup>The primary customer classes in Maine are Residential and Small Commercial (demand less than 20kW, 25kW, and 50kW, for Central Maine Power (CMP), Bangor Hydro-Electric (BHE), and Maine Public Service (MPS), respectively), Commercial (greater than 20kW, 25kW, or 50kW for CMP, BHE, and MPS, respectively, but less than 400kW for CMP and less than 500kW for BHE and MPS), and Industrial (demand greater than 400kW for CMP and greater than 500kW for BHE and MPS). Maine also uses the corresponding categories, as in Table III.1, Residential and Small Non-Residential, Medium Non-Residential, and Large Non-Residential.

The Commission has, at this time, completed a fourth year of competitive bids.<sup>19</sup> Table III.1 summarizes the results of each of the four rounds of bids. The Commission refers to the first two bidding experiences as meeting with “mixed results.” The last two years, however, have been much more successful for securing standard offer supply. In early 2004, the Commission reports that 63 percent of the state’s electric load were on standard offer service. About 66 percent of the medium commercial and industrial customers, 17 percent of the large commercial and industrial customers, and nearly all residential and small commercial customers are on standard offer service.<sup>20</sup>

While the bidding process for Bangor Hydro-Electric (BHE) was unsuccessful the first two years at finding acceptable bids for all customer categories, Central Maine Power (CMP) was only successful for residential and small non-residential customers. By the third year, all customer categories for both companies were served by acceptable standard offer prices found through the competitive bidding process. The standard offer price has increased for residential and small commercial customers since 2000, increasing 22 percent in BHE’s area and by 21 percent for customers in CMP’s area. The rates for these customers have been in effect since March 1, 2002 and will remain in effect through February 28, 2005. There has been no switching to competitive providers by residential and small commercial customers in either BHE’s or CMP’s areas (see Figures III.5 and III.6 below), consequently, all of these customers are on standard offer service. (There have been no direct offers to residential customers in the service areas of BHE and CMP since July 2001.) Currently all standard offer service prices for all customers classes for the three principle T&D utilities in the state have been procured through the competitive bidding process. The larger customer groups have been more active for these service areas, with considerable fluctuation in the large non-residential customer load in BHE’s service

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<sup>19</sup>This information is from the Maine Public Utilities Commission’s various postings on their website.

<sup>20</sup>State of Maine Public Utilities Commission, 2003 Annual Report, February 1, 2004.

territory. Large customer load in CMP's area has climbed to nearly 90 percent for June 2004.

For Maine Public Service (MPS), the bidding process has been able to obtain successful bidders despite the fact that MPS is in northern Maine and not part of the ISO New England control area. The Commission notes that while there has been some competition in this area, "there has been a limited number of suppliers active in the market."<sup>21</sup> The Commission noted in 2004 that a competitive supplier in northern Maine in 2003 stopped offering service to new customers, and customers began to return to standard offer service.<sup>22</sup> This supplier is one of the only two active suppliers serving northern Maine since retail access began in the state. The MPS standard offer price for residential and small commercial customers had increased by 35 percent between early 2001 and the price that went into effect in March of 2003. The standard offer rate in effect from March 1, 2004 through December 31, 2006, is about six percent lower than the previous year's rate. Commercial and industrial standard offer prices had increased 37 percent and 56 percent, respectively from 2001 to 2003. The 2004 through 2006 rates for commercial customers dropped slightly, about a half a percent, and industrial customers' rate increased by just over two percent.

MPS load served by competitive providers has fluctuated since the beginning of retail access (Figure III.7). About 60 percent of the total load was served by competitive suppliers in mid-2003, but that has since dropped to 47 percent of the load. Residential load has dropped to 13 percent of customer load, after peaking at 36 percent in July 2003. Medium and large non-residential customers, however, remain at 63 percent and 93 percent, respectively. Large customer load has been between 93 percent and 100 percent of the load since early 2002. In 2002, the total number of customers served by MPS was reported at 35,467 residential, 193 medium, and sixteen large customers.

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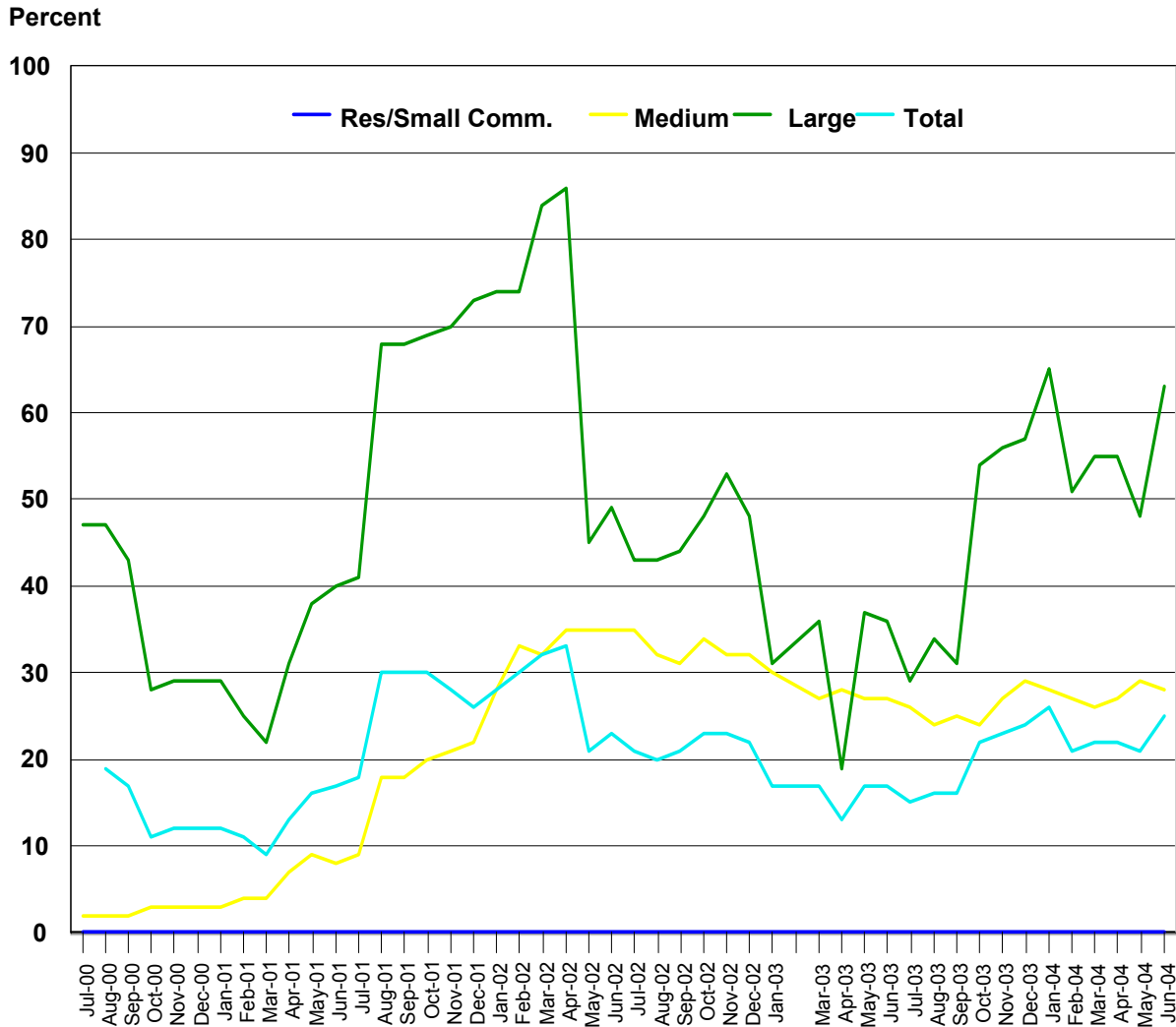
<sup>21</sup>Maine Public Utilities Commission, "Standard Offer Study and Recommendations Regarding Service After March 1, 2005," December 1, 2002, p. 8.

<sup>22</sup>State of Maine Public Utilities Commission, "2003 Annual Report," February 1, 2004.

**Table III.1.** Summary of Maine’s standard offer bidding process.

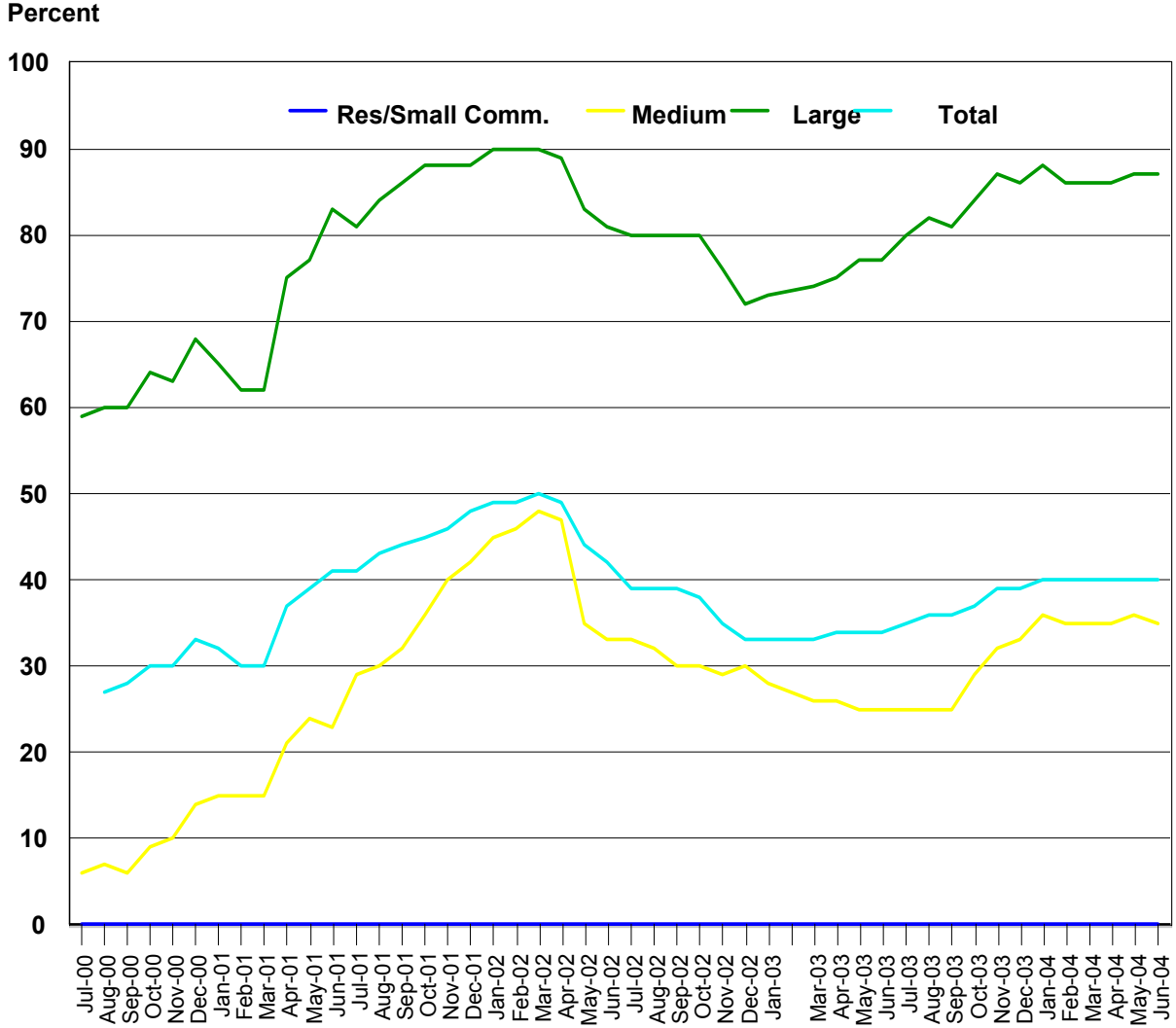
	<b>Year 1: for service beginning March 2000</b>	<b>Year 2: for service beginning March 2001</b>	<b>Year 3: for service beginning March 2002</b>	<b>Year 4: service beginning March 2003</b>
<b>Bangor Hydro-Electric Co. (BHE)</b>	All bids rejected – BHE directed by Commission to procure power in wholesale market for all 3 classes	All bids rejected – BHE directed by Commission to procure power in wholesale market for all 3 classes	3 year contract accepted for residential and small non-residential customers	Contract continues from March 2002 to February 2005
<b>Residential &amp; Small Non-Residential</b>				
<b>Medium Non-Residential</b>			1 year contract accepted for medium and large non-resid. customers	6 month contract March 1, 2004 through August 31, 2004
<b>Large Non-Residential</b>				
<b>Central Maine Power Co. (CMP)</b>	2 year contract accepted for residential and small non-residential	no bid – contract continues for this class	3 year contract accepted for residential and small non-residential customers	Contract continues from March 2002 to February 2005
<b>Residential &amp; Small Non-Residential</b>	Bids rejected – CMP directed by Commission to procure power in wholesale market for medium and large non-residential customers	Bids rejected – CMP directed by Commission to procure power in wholesale market for medium and large non-residential customers	1 year contract accepted for medium and large non-residential customers	6 month contract March 1, 2004 through August 31, 2004
<b>Medium Non-Residential</b>				
<b>Large Non-Residential</b>				
<b>Maine Public Service Co. (MPS)</b>	1 bidder chosen	three year term contract for all 3 standard offer rate classes (until 2/28/04)	no bid – contract continues for all classes	Contract March 1, 2004 through December 31, 2006
<b>Residential &amp; Small Non-Residential</b>				
<b>Medium Non-Residential</b>	service split 80/20 between 2 bidders			
<b>Large Non-Residential</b>	1 bidder chosen			

Source: From information in “Detailed Summary of Standard Offer Bid Processes and Results,” Maine Public Utilities Commission.

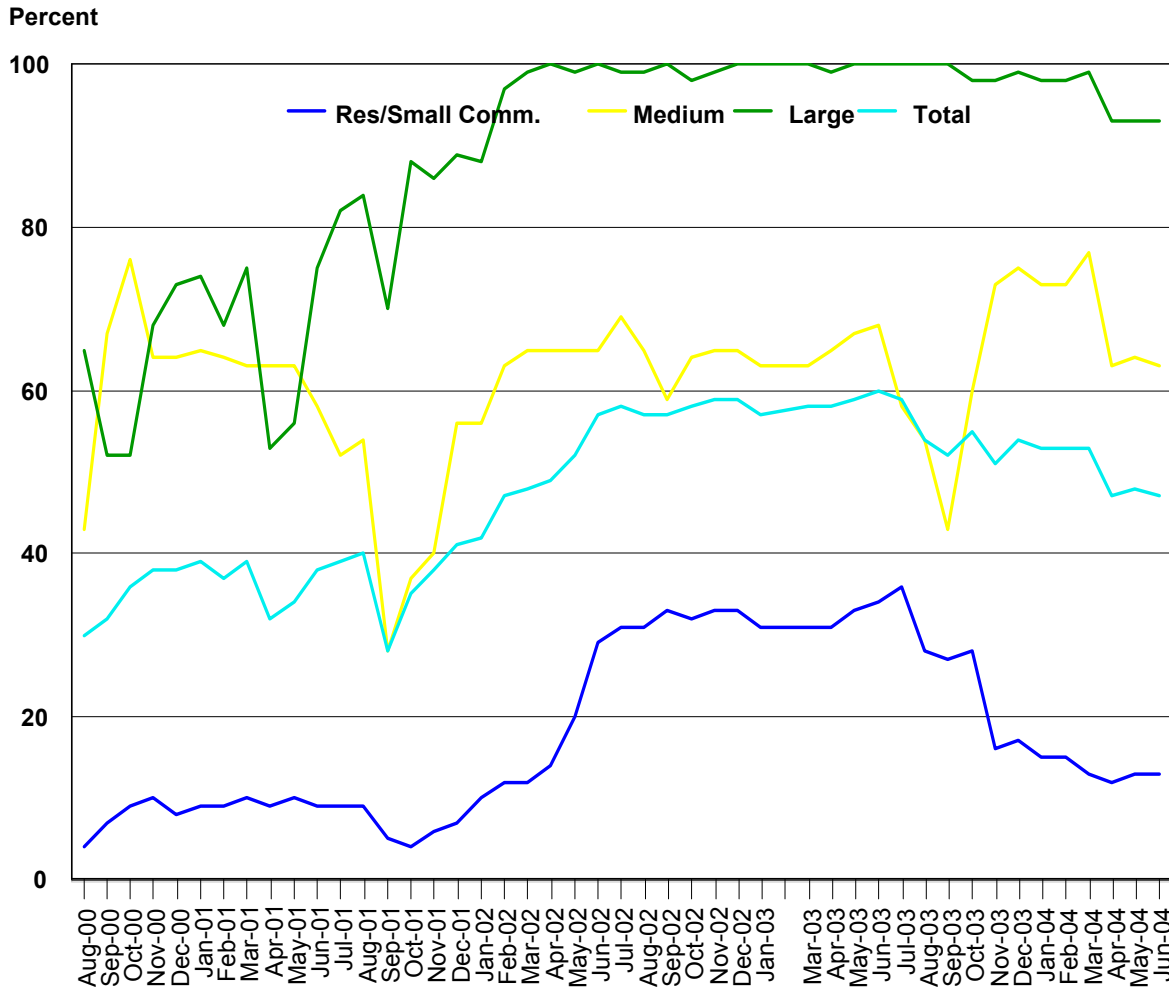


**Figure III.5.** Percentage of load served by competitive providers in Bangor Hydro-Electric Co.'s (BHE) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2004.





**Figure III.6.** Percentage of load served by competitive providers in Central Maine Power Co.'s (CMP) service territory. (Note: No data was reported for February 2003.)  
 Source: Maine Public Utilities Commission, June 2004.



**Figure III.7.** Percentage of load served by competitive providers in Maine Public Service Co.'s (MPS) service territory. (Note: No data was reported for February 2003.)  
 Source: Maine Public Utilities Commission, June 2004.

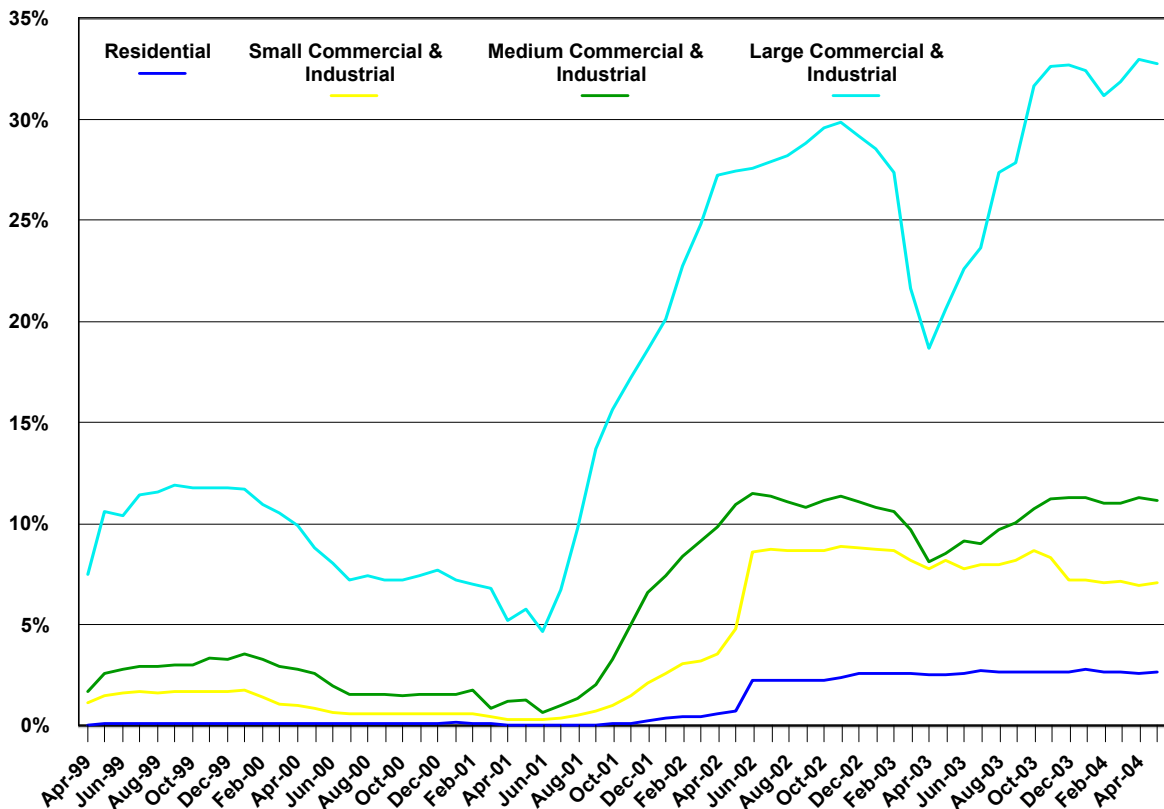
## Massachusetts

The Massachusetts Electricity Restructuring Law, passed in 1998, provides three electric generation service options to consumers: (1) standard offer service provided by distribution companies, a transition generation service available to each distribution company's customers through February 2005, and assigned to customers who had not selected a competitive supplier as of March 1, 1998; (2) default service provided by distribution companies, customers who move into a distribution company's service territory after March 1, 1998, are not eligible to receive standard-offer service and are placed on default service until they select a competitive supplier (which is higher cost than the standard offer); and (3) competitive generation service provided by competitive suppliers.

While there has been an increase in residential customer activity since 2002, statewide, it is still less than three percent of the customers that have switched to a competitive supplier. Figure III.8 shows the trends since April 1999 of the percent of customers choosing a competitive supplier by customer categories. The larger customer categories continue to show considerably more activity. There was a marked decrease from the fall of 2002 to mid-2003 for the large commercial and industrial customer group, which had fallen below 20 percent, but then increased to above 30 percent by late 2003. Small and medium commercial and industrial customer groups both remain at less than 12 percent of customers for each category. The pattern is similar in terms of kilowatt-hours, but at higher percentages, as shown in Figure III.9 below.

Figure III.10 and Figure III.11 are a cross section of customer switching activity for May 2004 to show where the activity is in terms of customer groups and kWhs for each of the distribution companies. Commonwealth Electric had the most activity across every customer group. This included residential customers, at 15 percent served by competitive suppliers, which was by far the highest in the state for any area. For the larger customer groups, Fitchburg and Massachusetts Electric large commercial

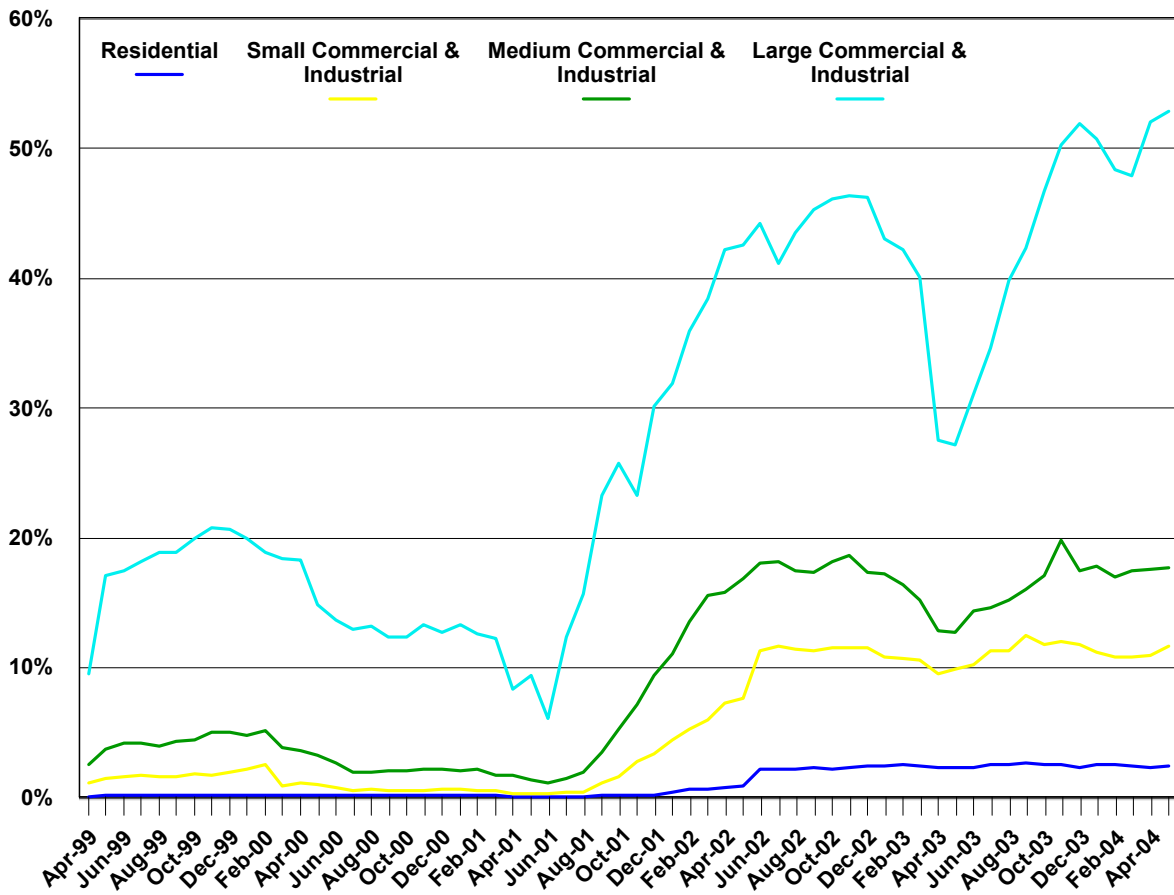
and industrial customers were both over 40 percent. Five of the seven company territories had over 25 percent of the large commercial and industrial customers being served by competitive suppliers. In terms of kWhs, all companies (except Nantucket) had large commercial and industrial customer load above 20 percent served by alternative suppliers. Fitchburg was over 80 percent of the large commercial and industrial load being served by competitive suppliers.



**Figure III.8.** Massachusetts percent of customers served by competitive generation, April 1999 to May 2004.\*

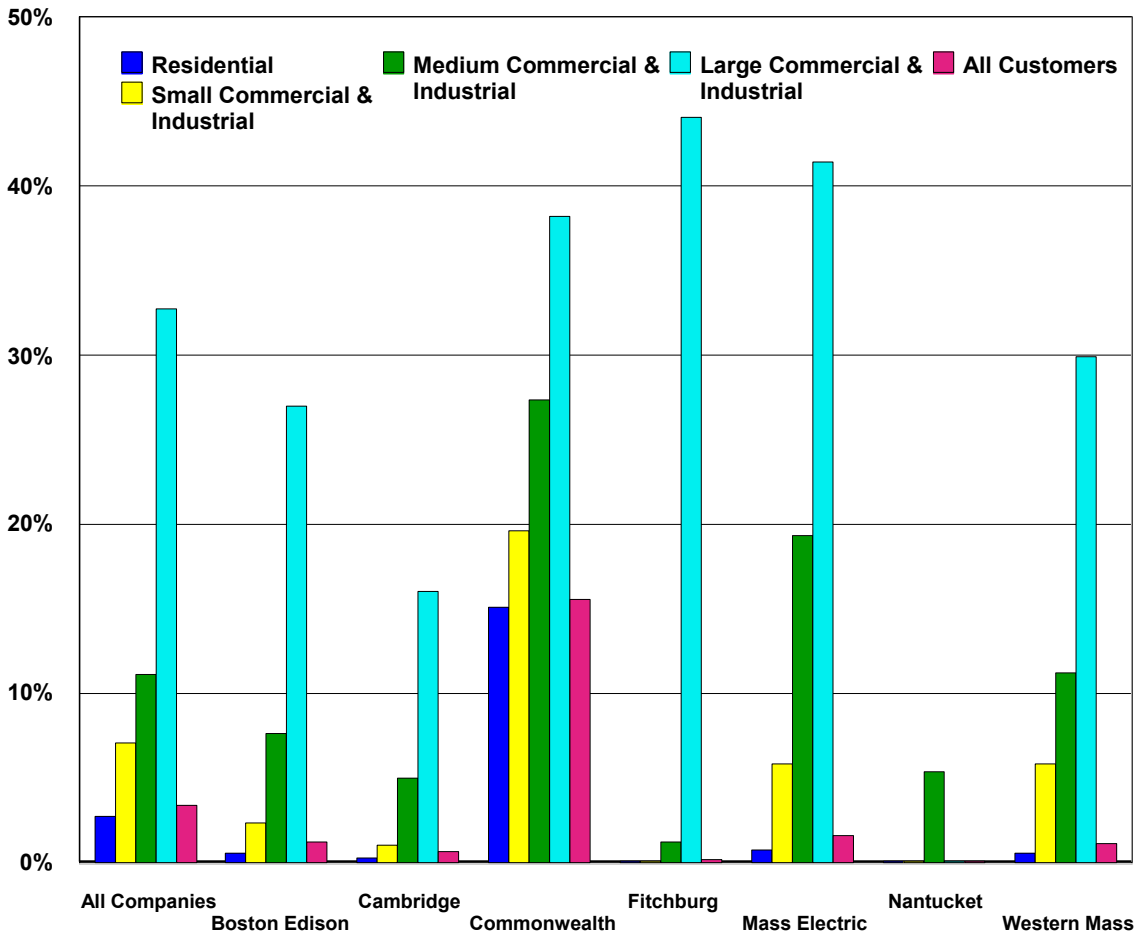
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through May 2004 reports.

\*The percentage calculated for Large Commercial & Industrial customers for July 2002 was omitted because it appeared to be incorrectly recorded.

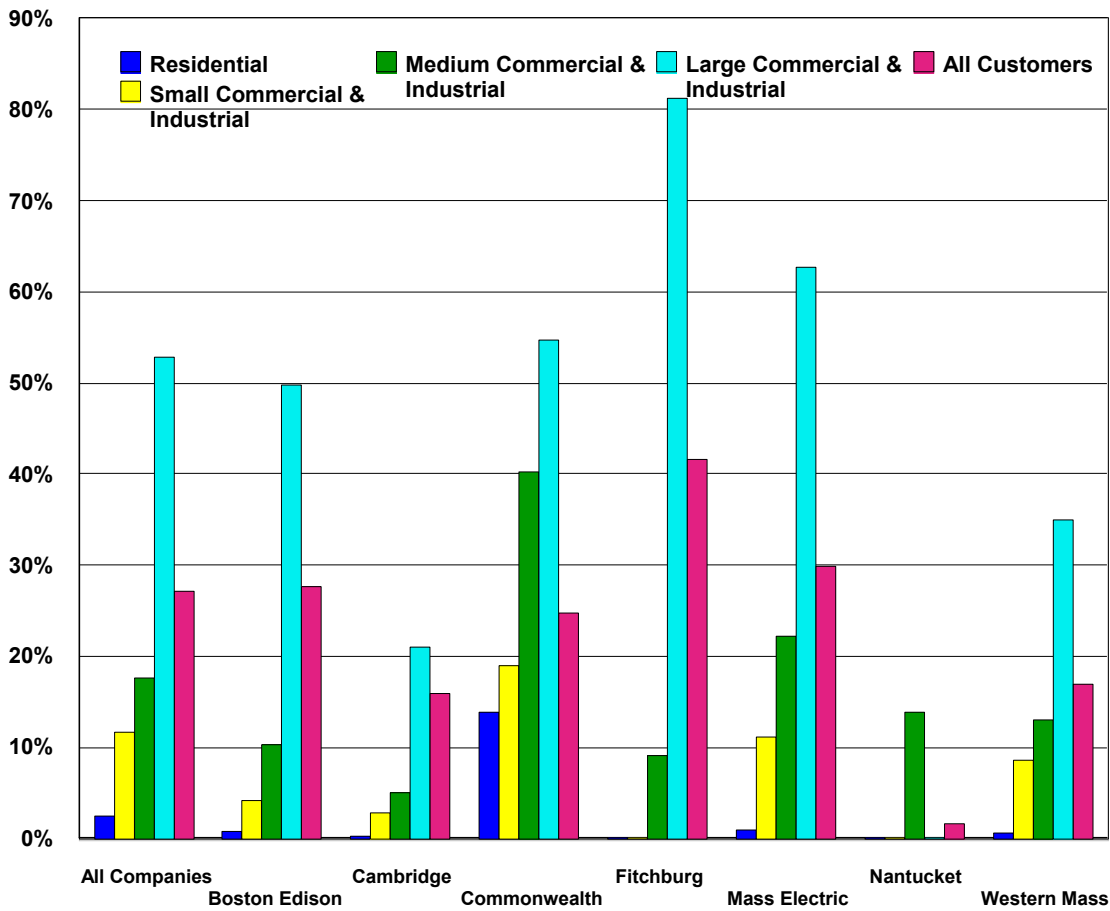


**Figure III.9.** Massachusetts percent of load (kWh) provided by competitive generation, April 1999 to May 2004.

Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through May 2004 reports.



**Figure III.10.** Massachusetts company comparison by percent of customers served by competitive suppliers, May 2004.  
 Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," May 2004 report.



**Figure III.11.** Massachusetts company comparison by percent of load (kWhs) served by competitive suppliers, May 2004.  
 Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," May 2004 report.

## **Section IV New York**

### **Wholesale Market**

The New York Independent System Operator (NYISO) operates the state's major transmission system and administers the wholesale markets for electricity in New York. The NYISO is a not-for-profit organization formed in 1998, is operated from a Power Control Center near Albany, New York and is governed by an independent, ten-member board. The NYISO developed directly from the New York Power Pool that was created by the state's eight largest electric utilities following the 1965 northeast blackout. The Power Pool coordinated the state's interconnected transmission system, designed and operated the control center, and developed the power pool's economic dispatch program. The NYISO began operations on December 1, 1999, after receiving FERC approval and assumed full operation of New York's wholesale electric system from the New York Power Pool. The New York summer 2004 total installed generating capacity is expected to be almost 38,000 MW.

The markets the NYISO currently operates are a day ahead market (where capacity, energy, and ancillary services are scheduled and sold for the following day), a real time market (where capacity, energy, and ancillary services are sold for one-hour periods), and ancillary services markets (which includes spinning reserve, 10-minute non-synchronized reserves and 30-minute reserves, and black start capability). In addition there are Transmission Congestion Contracts (TCC) and an Installed Capacity market (ICAP).

The NYISO has been concerned in recent years about the state's need for additional generation resources, particularly for New York City and Long Island. Of the 5,000 to 7,000 additional megawatts (MW) of generation originally recommended by the NYISO to be in place by 2008, more than 3,000 MW has been built and an additional 2,038 MW are under construction. There are also 3,120 MW approved by the siting



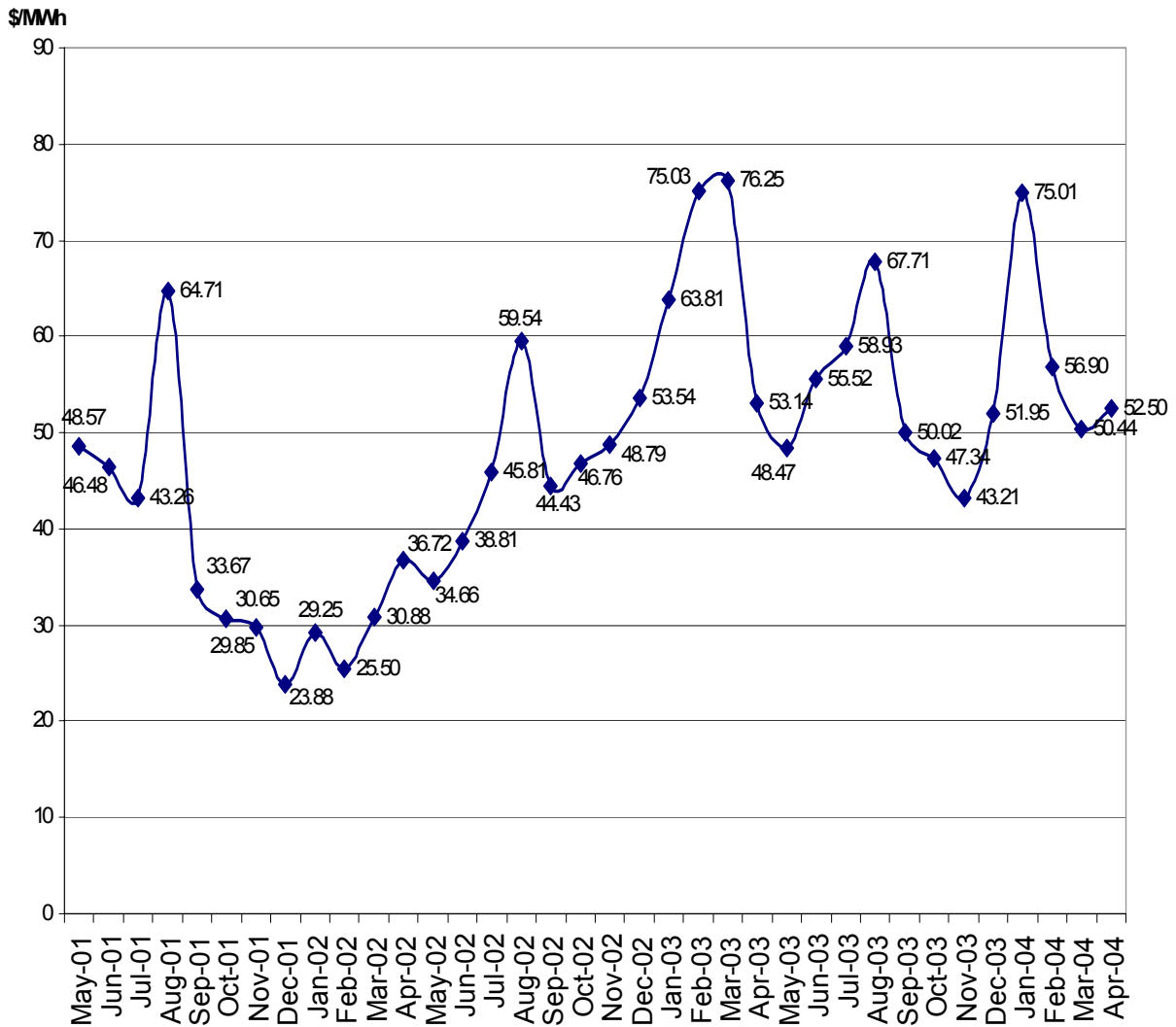
process, but are not assured of completion.<sup>1</sup> However, the NYISO projects that New York City and Long Island will not be able to meet their capacity requirements after 2008 unless new generation, that is not already under construction, is built or scheduled retirements are deferred. They are recommending that an additional 2,000 MW of new generation be added by 2009, mostly in New York City and on Long Island, and that 500 to 1,000 MW be constructed annually thereafter, depending on electricity demand growth.

Also according to the NYISO, only one new transmission line has been constructed in New York in more than a decade. This is a direct current cable that runs across Long Island Sound from Connecticut to Long Island. This "Cross Sound Cable" was built by a merchant enterprise and is in operation, but has faced legal challenges. Its continued operation will depend on the outcome of the litigation and possible congressional action.

Figure IV.1 shows the load weighted monthly average prices for the Day Ahead Market of the New York ISO from May 2001 to April 2004. As with other power markets around the country, the impact from the higher natural gas prices in early 2003 and January 2004 can be seen, when prices reached \$75 per MWh in February and March of 2003 and again in January 2004. Prices retreated to below \$50 per MWh in May of 2003 and reached a summer peak of over \$67 in August of 2003. It is worth noting that the highest prices for 2003 and 2004, and for the three year period, were reached in the winter months, not the summer as seen in 2001 and 2002. This reflects the particularly volatile natural gas markets at those times and the increased impact that natural gas prices now have on power prices (as discussed in Section I).

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<sup>1</sup>*ISO Power Trends, New York's Success & Unfinished Business*, Report by the New York Independent System Operator, May 2004.

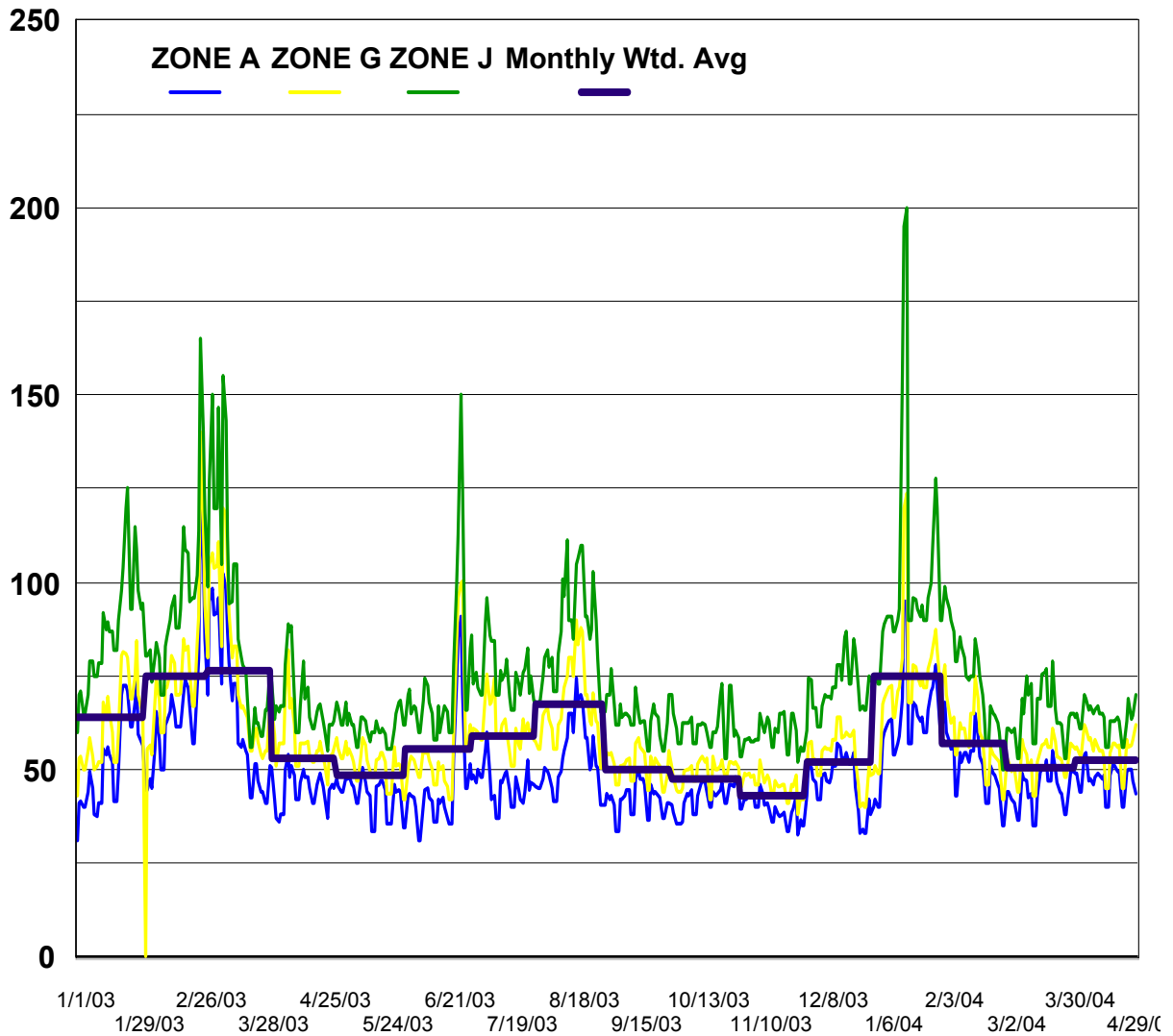


Data Source: New York ISO, May 2001 through April 2004.

**Figure IV.1.** New York ISO load weighted monthly average day ahead market prices.

Figure IV.2 graphs the daily variation in three New York ISO zones and the weighted monthly prices for January 2003 through April 2004. Zone A is the western most zone in the state, Zone G is the Hudson Valley region in the south eastern part of the state, and Zone J is New York City (there are a total of 11 zones in the state). The daily zone prices tend to fluctuate together, but the relatively resource constrained Zone J prices are consistently higher than the other two zones. While there were price spikes during the summer of 2003, the highest daily peaks were again during the winter

months in early 2003 and 2004—spiking to \$200 per MWh in January 2004. Power prices remained volatile into early spring as well in both years.



Data Sources: Platts Megawatt Daily and New York ISO, January 2003 through April 2004.

**Figure IV.2.** New York ISO Daily and Monthly Weighted-Average Prices.

## Wholesale Market Performance

The Independent Market Advisor (IMA), the NYISO's independent market monitor, issued a "State of the Market" report in May 2004<sup>2</sup> that included some market performance analysis. In an attempt to determine if there was physical withholding of capacity that could be an indication that suppliers were attempting to raise prices by exercising market power (as explained in Section 1), the IMA analyzed generator deratings. Deratings occur when a supplier reduces the output either completely or partially from a power plant. The IMA considered only non-planned outages in their analysis, assuming that "planned outages are legitimate and are not aimed at exercising market power" (p. 24). They also considered only hours of higher demand, on the assumption that withholding of generation resources would increase as demand increases. They only examine areas east of the Central-East interface, assuming that transmission and generation constraints in eastern New York would likely increase the opportunity to exercise market power. Based on this analysis, they concluded "that no (statistically) significant relationship existed between deratings and load level in 2003, which would lead us to reject the hypothesis that market power was systematically exercised through physical withholding" (p. 25).

This analysis is too restrictive to draw a conclusion that there was no exercise of market power in New York's wholesale market, only that they believed that market power was not being exercised through physical withholding based on their analysis. However, their analysis may be too limited to detect even this behavior since it is likely based on a faulty assumption—that is, if suppliers had market power and were withholding capacity, withholding would increase as demand increased. At high levels of demand, the supply curve becomes very or nearly vertical. During these hours, even withholding a small amount of capacity would have a considerable impact of the market clearing price for power. This would make it unlikely that there would be a direct correlation between withholding (deratings) and demand level even though some suppliers may in fact be exercising market power. Their analysis, in other words, may

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<sup>2</sup>2003 *State of the Market Report*, New York ISO, Potomac Economics, Ltd., Independent Market Advisor to the New York ISO, May 2004.

falsely reject the hypothesis of there being market power simply because there is no correlation between withholding of capacity and demand when market power is exercised.

Also, it is not certain the assumption that planned outages are always “legitimate” and are not intended to influence prices is a correct one either. While it is impossible to predict exactly when there will be the hottest days during the summer months, it is highly probable that those months will be warm and that most generating capacity will be needed. No mention is made if any analysis was conducted to determine if there has been any shifting of planned outages over the years from shoulder periods (spring and fall) to peak periods (summer and winter) or if there was a shift in when unplanned outages occurred.<sup>3</sup>

Finally, while it is reasonable to conclude that the constraints into eastern New York would make it relatively easier to exercise market power, there was no mention if any similar analysis was conducted for other areas of the state. There was also no discussion on whether the extensive price mitigation that occurred for the New York City load pocket during 2003 may have had any impact on their findings.

The IMA also conducted an “output gap” analysis to determine if there was economic withholding of capacity. They define “output gap” as “the quantity of generation capacity that is economic at the market clearing price, but is not running due to the owner’s offer price . . . [was] substantially above competitive levels” (p. 27). “Reference values” based on past offers during “competitive periods” are used to compare with supplier offer prices. The assumption is that suppliers will offer prices near their marginal cost during these “competitive periods,” since offers above marginal cost will not be selected for dispatch. Offers are considered above competitive levels if it exceeds reference values by the “mitigation threshold” (the lower of \$100/MWh or 300

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<sup>3</sup>While the evidence is circumstantial, FERC data indicates that in California there was a decrease in planned outages during the spring of 2000 when compared to the spring of 1999 and a increase during the early summer of 2000, when the western power crisis began. Unplanned outages increased considerably (over 400 percent increase) during the summer of 2000 when compared to 1999. This suggest both a shifting of planned outage to the higher demand season and possible deferral of maintenance that forces an unplanned outages and, of course, deliberate withholding during critical times.

percent) and a “low threshold” (the lower of \$50/MWh or 100 percent). Similar to their analysis of deratings, they assume that the “output gap” would increase as load increases, if suppliers are using economic withholding to exercise market power. Again the analysis is only done for eastern New York. The IMA found that there was “no correlation between load and the output gap” and concluded “that economic withholding was not a significant issue in New York in 2003” (p. 28).

Again, the analysis is too restrictive to draw a conclusion that there was no exercise of market power in New York’s wholesale market, only that the IMA believed that market power was not being exercised through economic withholding. However, it is also not clear if there would be a correlation between “output gap” and demand. They measured the “output gap” in megawatts (MW), however, it may be more likely there is a correlation between the “gap” in terms of price (that is, the difference between the reference price and bid, in \$/MWh) and demand. This could indicate that suppliers were able to obtain a higher price from economic withholding as demand increased. They did not report if this analysis was attempted using a “price gap” rather than a “output gap.”

Another limitation is the use of past offers as reference values. Their assumption that suppliers will bid close to their marginal cost presupposes that these are competitive periods of no or only limited market power. However, if this assumption is incorrect, and suppliers have some significant level of market power, then the reference price will be higher than marginal cost and not a suitable approximation. This would mean fewer MWs being identified as an “output gap,” because the spread between the reference value and the actual bid would be lower and less likely to exceed the thresholds. Also, the thresholds criteria is relatively large and again would mean fewer MWs being identified as an “output gap.” Both these limitations of the methodologies will lead to the incorrect conclusion that there is no significant economic withholding, when it could in fact be occurring.

By definition, supplier market power will impact prices, since it is the price leveraging ability (or power) to significantly raise prices above what would occur in a competitive market. Therefore, these approaches used by the IMA are, at best, an indirect approach aimed at detecting a secondary affect, the physical or economic

withholding of capacity to increase prices. At worst, this could lead to the conclusion that market power does not exist or is at sufficiently low level to not warrant any concern, when it is in fact significant. More rigorous and careful analysis than these are needed to draw more definitive conclusions about New York wholesale market performance.

The IMA conducted an evaluation of the reference prices in an attempt to see if their assumption that supplier offer prices are close to marginal costs (p. 37). The reference prices are also the basis for market mitigation in New York. To make this comparison, they compare average reference prices in the real-time market for fossil-fired units to estimated average variable production cost. They found that statewide, reference prices were three percent below average variable cost and with cogeneration units removed from the analysis, reference prices were 1.2 percent below average variable cost (p. 39). However, since the comparison is presented in a nonstandard manner (they use a per-megawatt average, rather than megawatt hours or other energy measure), it obscures the results and prevents a valid comparison of reference price and supplier costs. Other assumptions appear overly restrictive as well to provide useful results, such as, the comparison was made for only one day in each month of 2003.

## **Retail Market**

New York is the only state where the electric industry restructuring was not initiated by the state legislature. The New York Public Service Commission determined that it could begin restructuring with its existing authority under state law. In May of 1996, the NYPSC issued its order (Opinion 96-12) that restructured New York's electric power industry and opened the state's electric industry to competition.<sup>4</sup> This order required utilities to file rate and restructuring plans. In late 1997 and early 1998, the

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<sup>4</sup>In response to the May 1996 PSC Order requiring utilities to file restructuring plans, New York utilities filed suit against the PSC, contending that the PSC did not have jurisdiction to implement retail access or require divestiture of their generation assets. The case went to the New York Supreme Court where the Court determined that the PSC, under New York law, has such jurisdiction – allowing restructuring to proceed.

Commission approved six restructuring orders for the following utilities: Consolidated Edison Company of New York, Inc. (Con Edison); Central Hudson Gas and Electric Corporation (Central Hudson); Orange and Rockland Utilities, Inc. (O&R); New York State Electric and Gas Corporation (NYSEG); Niagara Mohawk Power Corporation (Niagara Mohawk or NIMO); and Rochester Gas and Electric Corporation (RG&E).

A seventh utility, Long Island Lighting Company's (LILCO's) transferred its electric transmission and distribution system and nuclear assets to the Long Island Power Authority (LIPA) in 1997. LILCO's gas assets and operations and its non-nuclear generating assets and operations were transferred to subsidiaries and then purchased in 1998, by corporate entities associated with Brooklyn Union Gas Company.<sup>5</sup> The NYPSC does not have pricing or operational regulatory authority over the LIPA system.

All of the orders originally required either rate reductions or freezes for all classes of customers and all but one of the orders (for RG&E) required divestiture of all, or substantially all, of the utilities non-nuclear generating facilities. There was a transition period of three to five years that phased-in competition to when all customers were eligible to purchase their electricity from alternative suppliers. During this transition period, rates for electricity and delivery services were set by the Commission. Also from the settlements, companies face financial penalties if reliability or customer service deteriorates from past levels. The utility settlements reached with the NYPSC are summarized in Text Box IV.1.

Currently, all rate caps and freezes have expired and all customers' power supply prices are being determined by the market, either from the supplier they chose or based on the ISO price. The two main components of the customers' price for power are for (1) generation services or the supply charge, which is based on the market price

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<sup>5</sup>KeySpan Corporation was formed from the merger of KeySpan Energy Corporation, the parent company of Brooklyn Union Gas, and certain businesses of the Long Island Lighting Company. KeySpan now owns and operates generating plants on Long Island and New York City with total capacity of more than 6,400 megawatts and serves approximately 1.1 million electric customers through a management service agreement with the Long Island Power Authority (information from <http://www.keysenergy.com/>).



for power, and (2) delivery services, which is the regulated rate for transmission and distribution services and other charges.

Most rates in the state have a delivery charge that include an adjustment factor to mitigate market volatility. For example, NIMO's rates have a *supply charge* based on the NYISO market price and a *delivery charge* that includes charges for transmission and distribution, "Competitive Transition Charge" (for "stranded cost"), "System Benefit Charge," and a "Delivery Charge Adjustment" (DCA). The DCA reconciles the forecasted market price with the actual market price to allow the company to recover customer supply costs and provides some mitigation against market price volatility.<sup>6</sup>

Customers may receive a credit for switching to an alternative supplier or Energy Service Company (ESCO) that is intended to reflect costs the utility avoids when a customer switches to another supplier. For example, NIMO residential and small commercial and industrial customers received a credit of 4 mills per kWh and all other customers receive a credit of 2 mills per kWh when they choose to received their generation service from an ESCO.<sup>7</sup> An ESCO may be an independent electricity supplier, or an affiliate of the former local utility or another utility company. Con Edison had a retail access incentive for small customers who signed up in April 1998 to buy power from an ESCO, and received a credit on their bill of \$50 for residential customers and \$75 for small business customers. These customers had to agree to stay with the ESCO for at least ten months. ESCOs were allowed discretion in using the incentive payment, including using some of the funds to cover marketing costs. Most customers who took the offer received a rebate.

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<sup>6</sup>Kajal Kapur, "New York Deregulation Model: Characteristics and Success," Energy Pulse, [www.energypulse.net](http://www.energypulse.net).

<sup>7</sup>Kapur, "New York Deregulation Model: Characteristics and Success."

**Text Box IV.1.** The following are highlights of the utility settlements reached with the NYPSC:\*

**Con Edison**

- 25 percent immediate rate decrease for large industrial customers, fixed for five years.
- 10 percent rate decrease for all other customers, phased in over five years.
- Con Edison rates for electricity and delivery will be set by the PSC during the transition.
- Con Edison customers who signed up in April 1998 to buy power from an ESCO got credit on their bill of \$50 for residential customers and \$75 for small business customers. Customers had to agree to stay with the ESCO for at least ten months.
- Retail Choice Phase-In Timing:
  - June 1, 1998 -- Choice of electricity supplier will become available to about 63,000 customers.
  - April 1, 1999 -- Choice of electricity supplier will be made available to about 300,000 more customers.
  - April 1, 2000 -- Choice of electricity supplier will be made available to about 300,000 more customers.
  - By December 31, 2001 -- All customers may choose an alternate electricity supplier.
- Con Edison agreed to auction off at least 50 percent of its electric plants in New York City by the end of 2002. Any fossil generation not sold by that date will be transferred to a deregulated affiliate of Con Edison.

**Central Hudson**

- Base electric rates frozen at 1993 levels through June 30, 2001, for all customers. (Base rates do not reflect changes in fuel costs.)
- Large industrial customers may choose to continue to buy electricity from Central Hudson and receive a 5 percent per year rate reductions until mid-2001, or they may select an energy services company (ESCO) whose price will be determined by the market.
- Central Hudson's rates for electricity and its delivery will be set by the PSC during the transition to full competition.
- Retail Choice Phase-In Timing (Commercial, Residential and Small Industrial Customers)
  - September 1, 1998 -- Choice of electricity supplier will become available to all customers on a first-come, first-served basis, but only up to 8 percent of Central Hudson's total electric load.
  - January 1, 1999 -- Choice will become available to customers up to another 8 percent of Central Hudson's total electric load.
  - January 1, 2000 -- Choice will become available up to another 8 percent of Central Hudson's total electric load, and on January 1, 2001, up to another 4 percent.
  - July 1, 2001 -- Choice of electricity supplier will be available to all Central Hudson customers.
- Central Hudson was required to separate its transmission and distribution (T&D) functions from its generation operations by no later than mid-2001. This restructuring will occur through the establishment of a holding company and the sale of fossil generation plants. The company's costs associated with its share of the Nine Mile Point Two nuclear power plant will remain with the T&D function.
- Central Hudson agreed to auction and transfer its fossil-fueled generating plants by June 30, 2001. The company may bid for the plants through a separate, unregulated affiliate. As an incentive for Central Hudson to maximize the proceeds from the sale of its plants and minimize stranded costs for its customers, the company will be allowed to keep 10 percent of the proceeds above the net book value up to a maximum of \$17.5 million if it does not participate in the auction.

## **O&R**

- During 1995 and 1996, O&R's electric rates decreased an average of 4 percent for residential customers and between 4 and 14 percent for commercial and industrial customers.
- On December 1, 1997, residential rates were reduced 1 percent, and they will be reduced an additional 1 percent on December 1, 1998.
- On December 1, 1997, large industrial customer rates were reduced by about 8.5 percent.
- For customers who participate in PowerPick by choosing to buy electricity from an energy services company (ESCO):
  - Large industrial customers may have additional rate benefits in the range of 3.5 percent.
  - Smaller customers may have additional rate benefits in the range of 2 percent.
- Prices for electricity purchased from any ESCO, and from O&R after May 1, 1999, will be determined by the market.
- On May 11, 1998, O&R and Consolidated Edison Company of New York, Inc. (Con Ed) signed a merger agreement under which Con Ed will acquire all of the common stock of O&R. O&R is now a wholly-owned subsidiary of Con Edison. Each company continues to operate under its current name, and their rate and restructuring plans were not affected.
- O&R required to hold an auction to sell its generating plants. The restructuring plan contains financial incentives for O&R to sell them by May 1, 1999.
- O&R will sell electricity only to customers who do not choose to purchase it from an ESCO. As the "provider of last resort," however, it will sell electricity to any customers who switch to an ESCO and then switch back to O&R.

## **RG&E**

- RG&E rates for sale and delivery of electricity set until mid-2002.
- The PSC regulates the utility's rates for delivery after 2002.
- Prices for the generation of electricity after 2002 determined by the market.
- Residential and small commercial customers will receive a 7.5 percent rate decrease phased in over five years.
- Other commercial and most industrial customers will receive an 8 percent rate decrease phased in over five years.
- Large industrial customers will receive a 11.2 percent rate decrease phased in over five years.
- Most customers will see bill decreases. However, some low use electric customers will see a slight increase in their electric bills because increases in the customer charge will not be completely offset by the lower electric rates. All customers pay a "customer charge" regardless of how much energy they use. The customer charge covers the average cost of being connected to the electric system, meters, billing and customer services.
- For residential customers the customer charge has typically been priced below cost. The monthly residential customer charge is being increased \$1.50 each year of the plan to approach paying the full cost of service. By tripling the average rate reductions from 2.5 percent to 7.5 percent, the PSC was able to reduce the number of customers affected by the customer charge change.
- Customer access phased in over three years:
  - July 1, 1998 -- 10 percent of electricity consumed in RG&E's territory will be open to competition. In addition, new customers or new load will have the ability to choose an alternate supplier.
  - July 1, 1999 -- 20 percent of electricity consumed in RG&E's territory will be open to competition.
  - July 1, 2000 -- 30 percent of electricity consumed in RG&E's territory will be open to competition.
  - July 1, 2001 -- All customers may choose an alternate electricity supplier.
- RG&E will separate its existing combined electric operations into the following different entities: regulated electricity supply company, regulated transmission and distribution

## **NYSEG**

- NYSEG's rates for both supply and delivery of electricity are capped until 2003.
- The PSC will continue to regulate rates for delivery after 2003.
- Prices for electricity for all customers after 2003 will be set by the competitive market.
- In a settlement approved by the PSC, NYSEG has agreed to forgo two previously authorized rate increases, saving customers over \$522 million through 2002.
- In addition, the following reductions in NYSEG's rates will apply to customers regardless of whether they stay with NYSEG or choose an energy services company (ESCO) for electricity:
  - Five percent per year rate decrease, for five years, for industrial and large commercial customers with over 500 kW of load capacity.
- Residential and small commercial/industrial customers will have:
  - Rates frozen at the current levels for two years.
  - Bills reduced 1 percent in the third year of the plan.
  - A total decrease of 5 percent by the fifth year of the plan.
- For industrial and commercial customers who are not eligible for the five annual 5 percent rate decreases, the plan provides financial incentives for load growth.
- November 1997 -- NYSEG began a Customer Advantage program allowing farms and food processors to buy electricity from a supplier other than NYSEG.
- August 1, 1998 -- Choice of electricity supplier will become available to all customers in the company's Lockport Division, the City of Norwich, and to all its industrial customers who are not eligible for the five annual 5 percent rate decreases.
- August 1, 1999 -- Choice of electricity supplier will become available to all remaining customers.
- NYSEG agreed to auction its seven coal-fired generation plants by August 1, 1999. The new owners of the plants will compete in the competitive electric generation market.

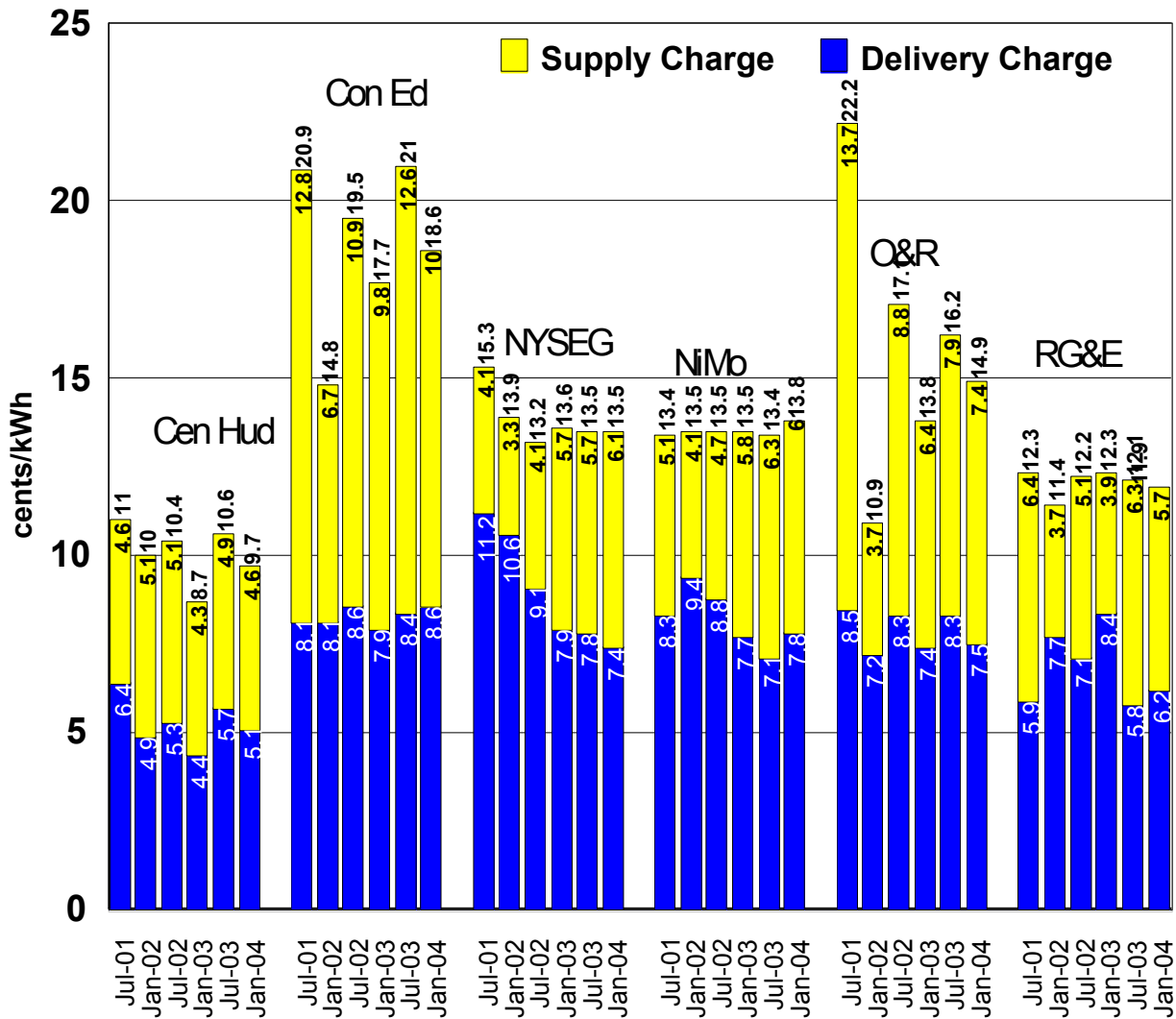
## **Niagara Mohawk**

- Niagara Mohawk's rates will decrease overall by an average of 4.3 percent.
- Residential and commercial customers will see an average phased-in decrease of 3.2 percent over three years.
- Industrial customers will see decreases of about 13 percent.
- Niagara Mohawk rates for electricity and its delivery are set until September 1, 2001.
- In 2001 and 2002, Niagara Mohawk may request limited rate increases, but the PSC must review and approve any request.
- In 2001 and 2002, prices for some of the electricity sold to all customers will fluctuate with changes in market prices.
- November 1, 1998 -- Choice of electricity supplier will become available for large industrial and commercial customers who use two or more megawatts of power.
- Retail choice phase-in:
  - April 2 - December 31, 1999 -- for residential customers.
  - May 1, 1999 -- retail choice will become available for all remaining transmission and sub-transmission industrial and commercial customers.
  - August 1, 1999 -- retail choice will become available for all remaining non-residential customers.
- Niagara Mohawk has agreed to remediate pollution on its land, donate 5,000 sulfur dioxide air emission allowances, assist in the development of more than ten megawatts of wind and solar generation, and donate and sell a number of Adirondack land parcels to the state.
- Niagara Mohawk sold its generation capacity and is now a subsidiary of National Grid, a U.K.-based company that also owns electricity distribution operations in New England.

\*Source: New York State Public Service Commission,  
<http://www.dps.state.ny.us/energyarch.htm#facts>

Figure IV.3 compares the residential rates for the six major electric companies in New York. The figure shows the delivery charges and supply charges for each company from July 2001 to January 2004. As noted these charges are general categories for the various charges customers pay. The subcategories under the heading of delivery and supply charges are different for each company and the specific amounts of the charges, which are adjusted each month, also vary by company. For example, Central Hudson residential customers' delivery charge is composed of a basic service charge, delivery charge (for transmission and distribution), purchased power adjustment, system benefit charge, customer refund, miscellaneous charges, and taxes. The supply charge is composed of a market price charge, market price adjustment, and taxes. Central Hudson and Con Edison have an adjustment subcategory for both delivery and supply charges. Niagara Mohawk and O&R have the adjustment made on the delivery charge (as noted, for energy market cost changes). NYSEG and RG&E do not have a subcategory for adjustments, however, both the delivery and supply charges, as with all the companies, have changed from month-to-month.

In terms of overall price paid by residential customers, all companies except one have had a decrease in total price per kWh during the period shown in the graph. The exception was Niagara Mohawk, which saw a slight increase.



Data Source: State of New York, Department of Public Service, July 2001 through January 2004.

Figure IV.3. Residential price comparisons by distribution company.

Table IV.1 shows the number of energy service companies (ESCOs) that have met the New York State Public Service Commission's and utility's requirements to provide service to retail customers in the state and the number of companies that are currently serving customers, by distribution company. Some of the ESCOs counted in the table as serving customers currently may not be making offers to new customers at the time when the numbers were collected (June 2004).

**Table IV.1.** Qualified Energy Service Companies (ESCOs) and those serving residential and non-residential customers, June 2004

Company	Residential Customers		Non-Residential Customers	
	Qualified ESCOs	Currently Serving Customers*	Qualified ESCOs	Currently Serving Customers*
<b>Central Hudson</b>	2	2	6	6
<b>ConEd</b>	10	9	19	17
<b>NiMo</b>	12	12	20	19
<b>NYSE&amp;G</b>	10	10	16	15
<b>O&amp;R</b>	7	6	13	12
<b>RGEC</b>	1	1	4	3

\*Number of companies that are currently serving retail customers, but may not be currently making offers to new customers.

Source: New York State Department of Public Service, June 2004.

Figure IV.4 summarizes customer switching, or "migration," in New York State and compares May 2002 and 2003 and March 2004 percentages. The top graph in Figure IV.4 is of residential customers, which shows that the most active shopping for these customers in the state is in the Orange and Rockland Utilities and Rochester Gas

and Electric service areas.<sup>8</sup> The bottom graphs shows a similar pattern of activity overall for these two companies for non-residential customers, but with high percentages for the large non-residential customers in March 2004 (large non-residential, time-of-use customers<sup>9</sup>) in three other company areas. O&R and Niagara Mohawk had modest gains in the percent of residential customers switching to alternatives from 2003 to 2004. RG&E and Con Edison had declines and Central Hudson, LIPA, and NYSEG were essentially unchanged from 2003 to 2004 for residential customers.

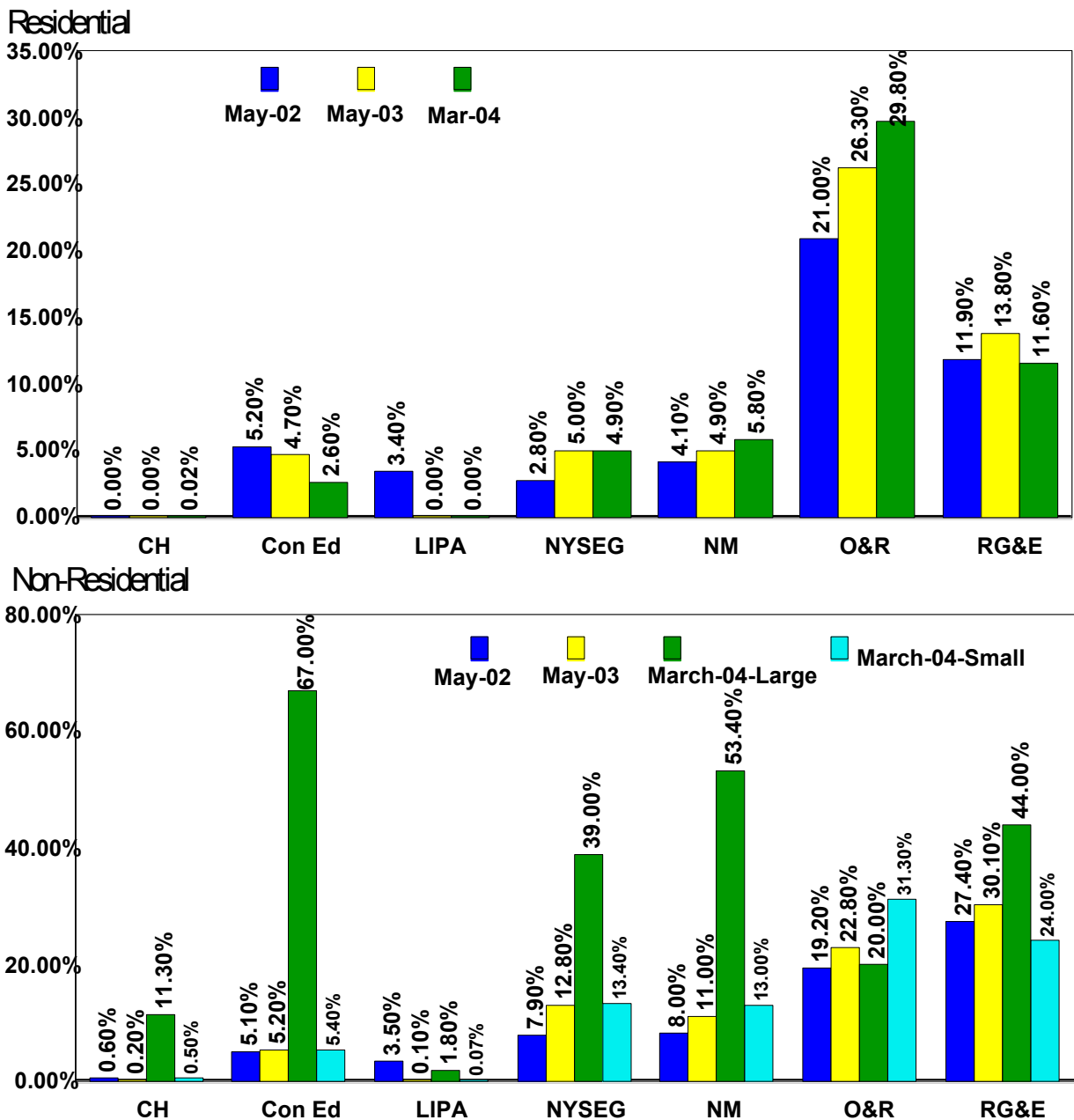
The percent of customer load (MWh) that has migrated to alternative suppliers, as shown in Figure IV.5, is generally higher for non-residential customers than residential load and, except for the Long Island Power Authority's area and Central Hudson's small non-residential customers, are at relatively high levels across the state's service territories. Large non-residential customer load in Con Edison's service area reached nearly 80 percent of load for March 2004, the highest percentage for any area, customer group, and for any year in the state. For residential customers, however, the Orange and Rockland Utilities and Rochester Gas and Electric service areas remain the most active, with all other areas below seven percent in 2004.

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<sup>8</sup>The full company names that are abbreviated in the figures are as follows: CH is Central Hudson Gas & Electric Corp.; Con Ed is Consolidated Edison Company of New York, Inc.; LIPA is Long Island Power Authority; NMPC is Niagara Mohawk Power Corp.; NYSEG is New York State Electric & Gas Corp.; ORU is Orange and Rockland Utilities, Inc.; and RGE is Rochester Gas and Electric Corp.

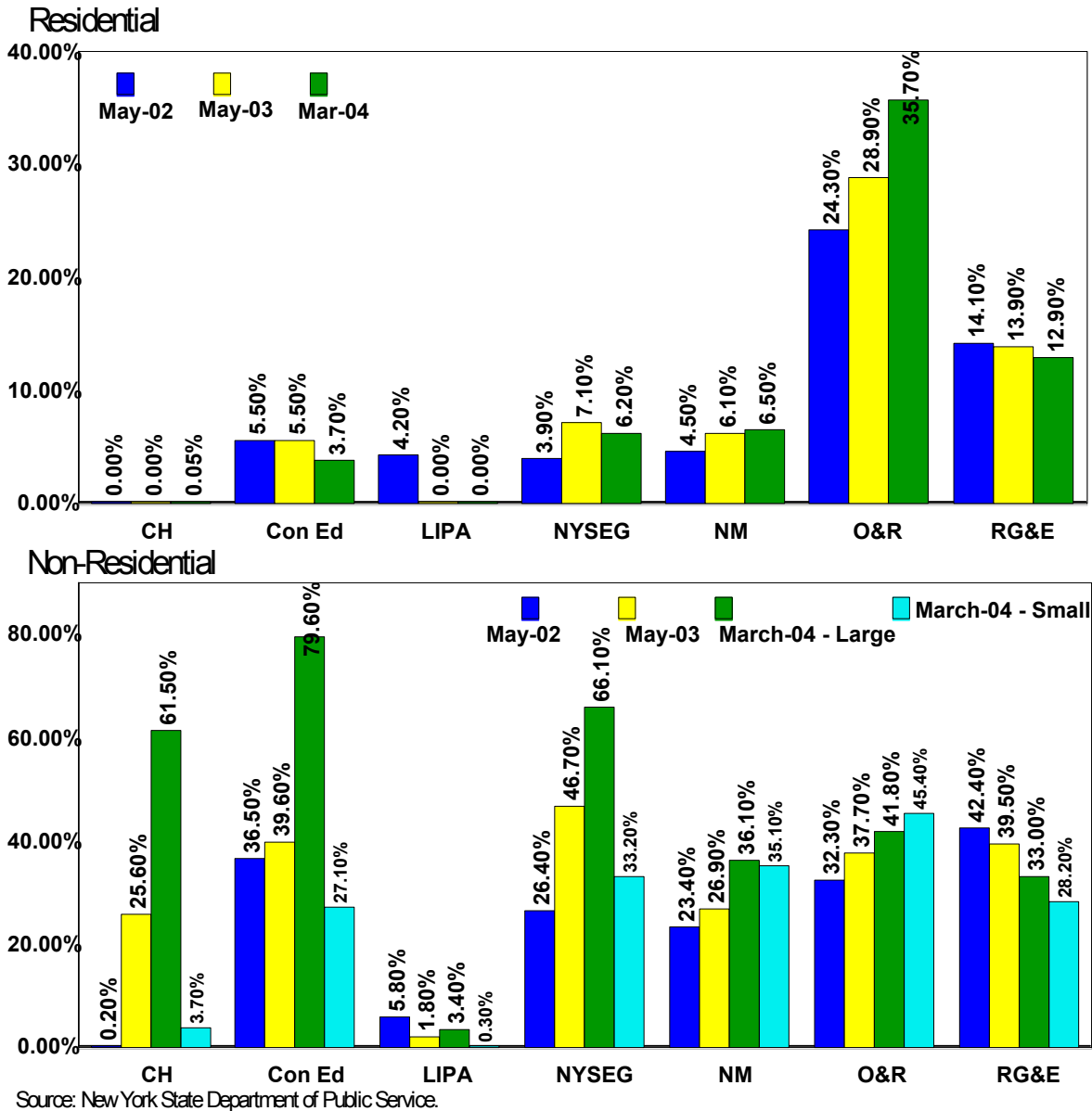
<sup>9</sup>This customer category was not reported separately in the previous years.





Source: New York State Department of Public Service.

**Figure IV.4.** Percent customer migration in New York, residential and non-residential customers.



**Figure IV.5.** Percent load migration (MWh) in New York for residential and non-residential customers.

## **Section V Midwest**

### **Wholesale Market**

The Midwest is an area that has an extensive transmission system that interconnects the utility systems throughout most of the region. Historically, however, the region has operated as independent utility systems, not as a single tightly coordinated system as other systems in the country have. PJM and New England, for example, operated for a long period as a coordinated system or power pool before they became an ISO. With the transmission system in the Midwest, these independent utility systems have been able to coordinate their systems to support increasing volumes of wholesale sales in the last two decades. However there are some areas with transmission “bottlenecks,” that limit the amount of power transfers within the region.

A significant part of the Midwest region formed the Midwest ISO (MISO), which was founded in February 1996, to begin the process of forming a more tightly integrated regional system. MISO became the first FERC-approved RTO in December of 2001 and began operation in February 2002 as a transmission provider and selling transmission service under its open-access transmission tariff. MISO covers an area that has more than 155,000 MWs of generation capacity with more than 97,000 miles of transmission lines. It covers a large area of the country that includes all or parts of 15 states and also one Canadian province, or 1.1 million square miles and 16.5 million customers. Figure V.1 is a map that highlights MISO’s geographic area.

Currently, MISO is responsible for short-term reliability and interchange schedules. At this time, the wholesale market transactions in the region are only bilateral trades. While there is currently no centralized energy market, MISO is planning the operational launch of day-ahead and real-time energy markets on March 1, 2005. Market trials are scheduled to begin December 1, 2004. MISO now uses transmission loading relief (TLR) for congestion management, but plans to use Locational Marginal Pricing (LMP, that will be determined in the energy markets) and Financial Transmission

Right (FTR), similar to what other RTOs or ISOs are currently using. MISO also is the provider of last resort for ancillary services.

About 60 percent of the region's capacity are coal-fired power plants. As with the trend nationwide, most of the recent capacity additions use natural gas, which is now about 16 percent of the capacity. The resource margin for the MISO is over 20 percent (the percentage that capacity exceeds peak load).



**Figure V.1.** The Midwest ISO operating region.  
Source: Midwest ISO, July 2004.

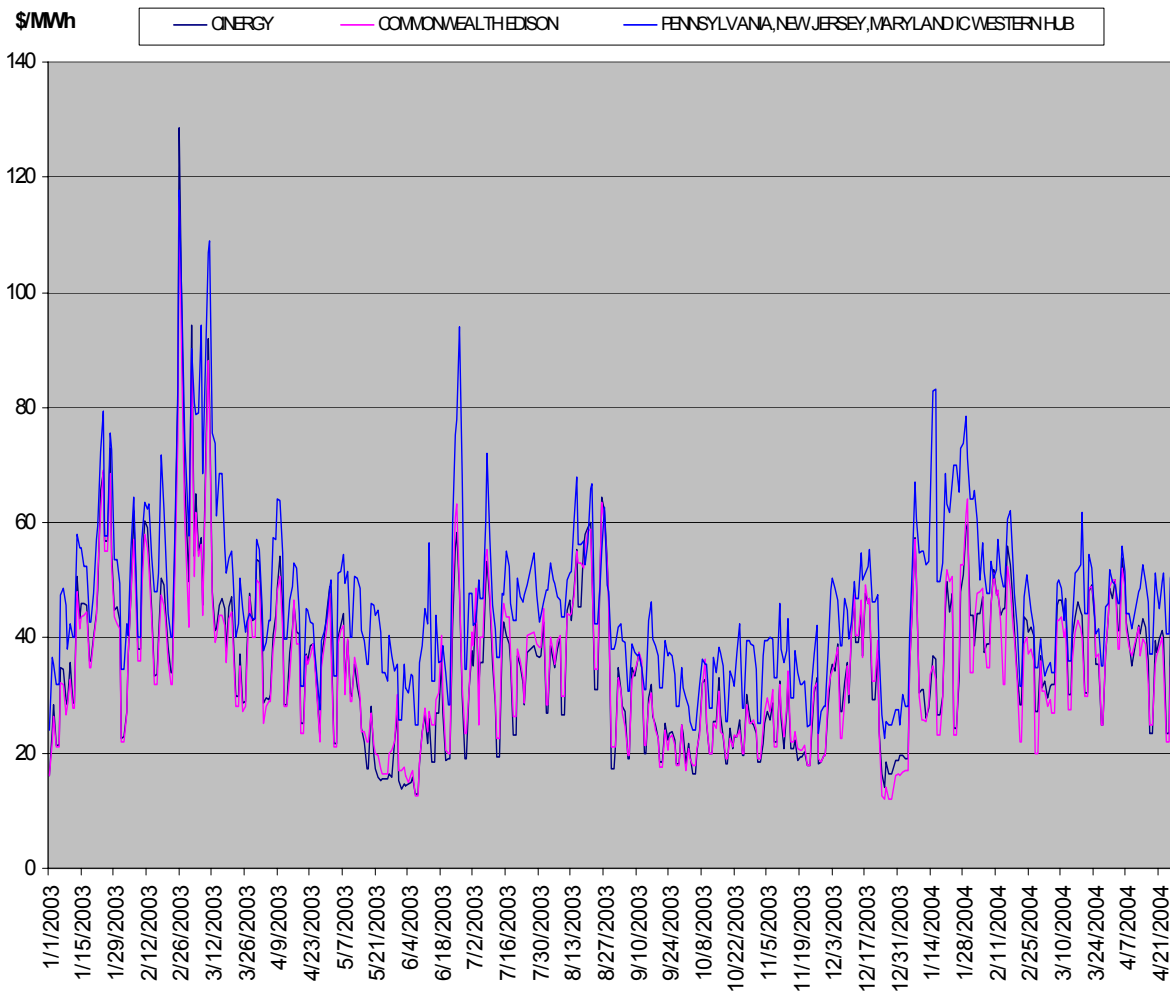
All of the currently operating and fully functional ISOs or RTOs, New England, New York, PJM, Texas, and California, had previous histories of at least some coordination or are within the borders of a single state. It is proving to be more difficult to form a functioning RTO over such a sizable area that crosses multiple state lines without this history of close coordination.

MISO and the Southwest Power Pool (SPP) mutually agreed to terminate a merger of their organizations in March 2003. SPP filed with FERC in October 2003 to become an RTO, which FERC conditionally approved in February 2004. SPP made another filing with FERC in May 2004 describing how they plan to meet FERC's conditions.

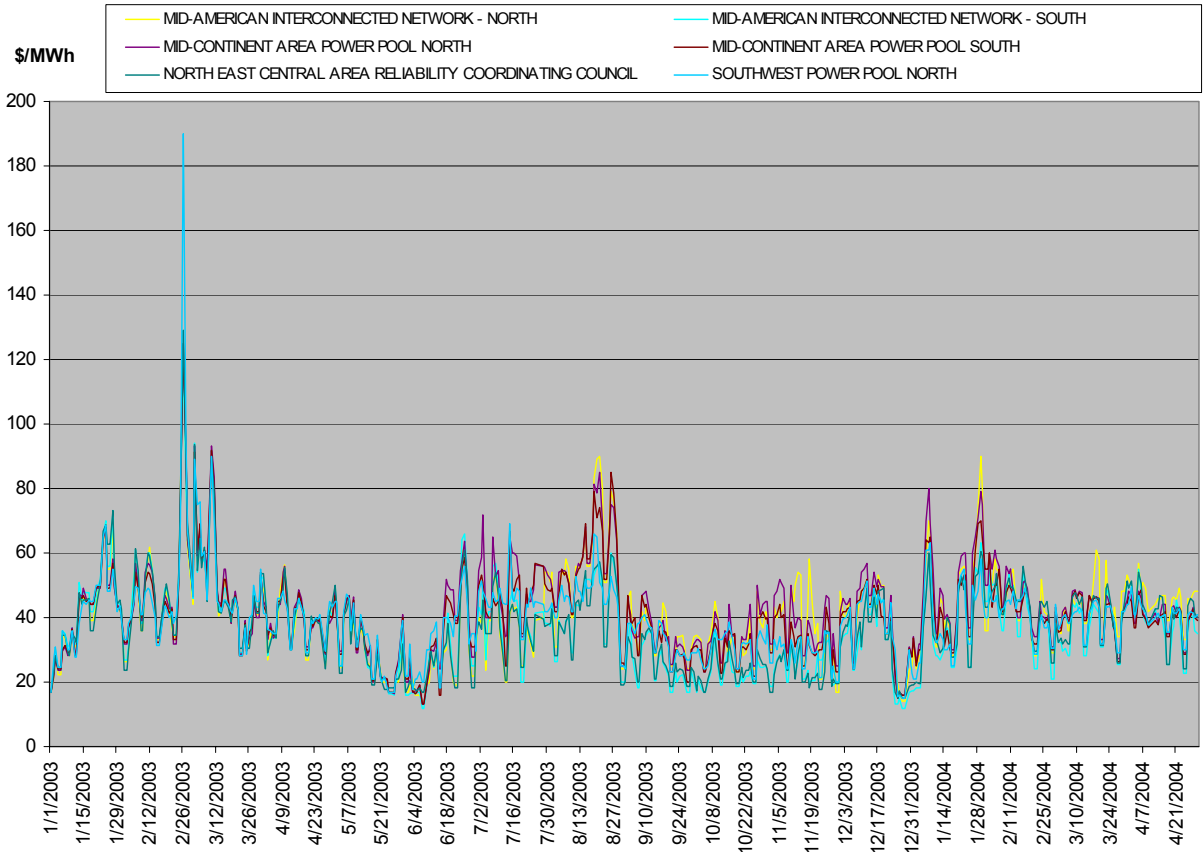
At this time, MISO, PJM, and SPP are working to form a "joint and common energy market" to coordinate power flows across the three regions.

### Midwest Wholesale Prices

Figure V.2 and Figure V.3 plot the weighted average daily prices for several Midwestern trading hubs for January 2003 through April 2004. The data are from Platts, *Megawatt Daily*. Figure V.2 are for the Cinergy (southeastern Ohio), Commonwealth Edison (northern Illinois), and the PJM-western region. The PJM Western region now covers parts of western Pennsylvania and Maryland, northern Virginia, most of West Virginia, into southeastern Ohio, and northern Illinois (there is a map in Section II). The plan is for PJM to extend beyond these areas and include more of the Midwest—including most of Ohio and portions of Indiana and Michigan. Figure V.3 are the mid-continent trading hubs in the western portion of the Midwest area. The hub prices generally move in tandem, but over a wider range than other more centralized and higher volume markets. While natural gas is only about 16 percent of the capacity, since it is the marginal fuel and as in other electricity markets, the impact of natural gas prices in early 2003 and 2004 can again be seen in the price for power.



**Figure V.2.** Weighted average daily prices for three Midwestern trading hubs, January 2003 through April 2004.  
 Data Source: Platts, *Megawatt Daily*.



**Figure V.3.** Weighted average daily prices for six Midwestern trading hubs, January 2003 through April 2004.  
 Data Source: Platts, *Megawatt Daily*.

### Retail Markets

Three states in the Midwest have retail access, Illinois, Michigan, and Ohio. The status of each state is briefly updated below.

#### Illinois

In December 1997, Illinois enacted into law the Electric Service Customer Choice and Rate Relief Law of 1997. Retail access was phased-in, beginning on October 1, 1999 for approximately 64,000 non-residential electric customers, about one-seventh of

all non-residential customers. An additional 609,000 non-residential customers became eligible to choose a new electric supplier on January 1, 2001. Retail access for the approximately 4.4 million residential customers began on May 1, 2002. Currently, all customer classes are eligible to choose an alternative suppliers in the state. Also in May of 2002, the Illinois legislature extended the current freeze on electricity rates until the end of 2006. The Illinois Commerce Commission reports that no supplier has sought permission from the Commission to serve residential customers, consequently, no residential customer have switched to an alternative supplier in the state. The Commission also reports that at the end of 2003, ten suppliers were serving non-residential customers.

Two distribution companies are reporting no activity in their areas for all customer categories in mid 2004, Interstate Power and Light Co. and MidAmerican Energy Co. AmerenUE Co. reported very little activity, one large C&I customer of 39 total customers in the class and two small C&I customers of 7,559 total customers in the class chose an alternative supplier. Three companies, AmerenCIPS Co., Commonwealth Edison Co., and Illinois Power Co., have had some customer switching, primarily among larger customers.

Table V.1 contains the percent of customers that are receiving “delivery services.” This includes Interim Supply Service, Power Purchase Option, and Retail Electric Supplier customers. The Illinois Commerce Commission (ICC) defines Interim Supply Service as a tariffed short-term service available to delivery services customers who have no source of electric supply and Power Purchase Option (PPO) as an unbundled, market-based generation option that non-residential customers subject to transition charges must be offered. Both Interim Supply Service and PPO are supplied by the incumbent utility.<sup>1</sup> Currently, according to the ICC, only two utilities, Commonwealth Edison and Illinois Power, charge transition charges to customers who receive delivery services.

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<sup>1</sup>Illinois Commerce Commission, “Assessment of Competition in the Illinois Electric Industry in 2002,” April 2003.



The ICC reports that for May 2004 over 42 percent of Commonwealth Edison’s delivery services customers were PPO customers. Over 91 percent of Illinois Power delivery services customers were PPO customers, 94 percent of the customers under one MW were taking PPO service. About 67 percent of Illinois Power’s larger-use delivery services customers (greater than one MW) switched to PPO.

Table V.2 shows the percentage of delivery service customers using PPO by utility and demand level. The ICC has previously noted that reliance on PPO may be cause for concern for the long-term development of the market, primarily because of the temporary nature of the PPO. They note, however, that electric utilities will cease offering PPO by the end of 2006, when the statutory “Mandatory Transition Period” ends.

**Table V.1.** Percentage of customers receiving delivery services, May 2004.

	Residential	Commercial	Industrial	Total		
AmerenCIPS Company	0.0%	1.0%	28.2%	0.2%		
	Residential	Small C&I	Large C&I	Govern mental	Other	Total
Commonwealth Edison Company	0.0%	5.4%	74.6%	2.9%	1.0%	0.6%
	Residential	Demand Less Than 1 MW	Demand Greater Than 1 MW	Total		
Illinois Power Company	0.0%	1.5%	40.3%	0.2%		

Source: Illinois Commerce Commission, May 2004.

**Table V.2.** Percentage of Delivery Service Customers on Power Purchase Option, May 2004.

Utility	Less Than 1 MW	Greater Than 1 MW	Total
<b>Commonwealth Edison Co.</b>	43.0%	33.6%	42.6%
<b>Illinois Power</b>	93.9%	67.0%	91.6%

Source: Illinois Commerce Commission, May 2004 update.

## Michigan

Michigan started retail access for all customers of Michigan investor-owned utilities on January 1, 2002. Table V.3 shows the percent of sales that have switched to alternative suppliers for Michigan's two largest investor-owned companies, which together provide service to almost 90 percent of the state's electric customers. While there is almost no activity among residential customers, there has been activity with larger customer groups, particularly with industrial customers in both companies' territory and with commercial customers in Detroit Edison's territory.

**Table V.3.** Percent of sales (MWh), end of first quarter 2003 and November 2003.

	Consumers Energy		Detroit Edison	
	2002	Nov. 2003	2002	Nov. 2003
Residential	0.000%	0.000%	0.005%	0.007%
Commercial	4.7%	6.7%	10.7%	20.3%
Industrial	10.4%	16.0%	8.8%	16.3%
Total	5.3%	8.2%	7.3%	15.0%

Source: Michigan Public Service Commission, "Status of Electric Competition In Michigan," February 1, 2004.

## Ohio

Ohio's restructured electric generation market began January 1, 2001. The state remains in a transition period or a "market development period," which for most utilities continues until the end of 2005, during this time incumbent distribution utilities continue to provide standard offer service to customers who do not choose an alternative supplier and to those customers whose chosen supplier defaults in providing service. Also during this period customers receive standard offer service at prices approved by the Public Utilities Commission of Ohio (PUCO) and residential customers receive a five percent rate reduction on the distribution utility's unbundled generation service component. After the market development period, standard offer service may be provided at market rates, that could be obtained by competitive bidding for either the

customer accounts or the load. A distribution utility, that offers both competitive and non-competitive services, is required to form separate affiliates and meet accounting requirements determined by the PUCO. The utility needs to obtain approval of the PUCO for the corporate separation plan.

In August 2001, the PUCO approved rules for allowing electric demand aggregation by local governments. These rules require local governments to obtain majority support of the community to act as an aggregator. Under Ohio's law the customers are automatically enrolled with the community's chosen supplier unless a customer returns an "opt-out" card mailed to all eligible customers. The North East Ohio Public Energy Council (NOPEC) formed an electric buying group that represents 112 communities in Northeast Ohio with more than 350,000 residential customers in eight counties. This is the largest public aggregation of electricity customers in the U.S.

The percentages of customers that switched to an alternative supplier for each distribution company is shown in Figure V.4. Cleveland Electric Illuminating Company<sup>2</sup> had the highest percentage of all customers switching to alternatives of Ohio electric distribution companies and for all customer classes except industrial. Switching of its residential, commercial, and for total customers were all above 70 percent for each category. Toledo Edison had the highest percentage of industrial customers at almost 66 percent. Toledo Edison also had a relatively high percentage of other customers switching, with residential, commercial, and total customer categories at almost 50 percent or greater switching to alternative suppliers. All of the Ohio Edison customer categories were above 30 percent. For the other five distribution companies, no category exceeded six percent customer switching, except for industrial customers of Dayton Power and Light, with was above 16 percent. Columbus Southern Power, Dayton Power and Light, Monongahela Power, and Ohio Power Company reported no

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<sup>2</sup>The full company names of the abbreviations used in the figures are as follows: CEI, Cleveland Electric Illuminating Co.; CG&E, Cincinnati Gas and Electric Co.; CSP, Columbus Southern Power Co.; DP&L, Dayton Power and Light Co.; Mon Pwr, Monongahela Power Co.; Ohio Ed, Ohio Edison Co.; Ohio Pwr, Ohio Power Co.; TE, Toledo Edison Co.

residential customers had chosen an alternative supplier. Cincinnati Gas and Electric had less than four percent residential customer switching.

In terms of megawatt-hour sales, shown in Figure V.5, the pattern is similar for Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison, except for industrial sales for Toledo Edison that was below four percent. Also, there was considerably more activity for commercial and industrial sales for Cincinnati Gas and Electric and for Dayton Power and Light. Dayton Power and Light industrial sales percentage was the highest of any distribution company, at over 64 percent. It should be noted that Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison (all part of FirstEnergy Corporation serving northern Ohio) had the highest regulated rates among investor-owned utilities prior to restructuring and, consequently, higher prices-to-compare than other parts of the state.

Customer aggregation by local governments in the area of Toledo and by Northwest Ohio Aggregation coalition and NOPEC in other areas contributed to substantial switching in the services areas of Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison. As of March 2004, aggregation programs account for almost 95 percent of residential, almost 88 percent of the commercial and only just under seven percent of the industrial customer switching in Ohio and almost 94 percent of all customer switching in the state. Table V.4 summarizes the aggregation program switching.

**Table V.4.** Aggregation activity in Ohio, March 2004.

	<b>Customer Switching through Aggregation</b>	<b>Total Customer Switching</b>	<b>Percent Switching through Aggregation</b>
<b>Residential</b>	853,229	899,527	94.85%
<b>Commercial</b>	104,737	119,523	87.63%
<b>Industrial</b>	119	1,731	6.87%
<b>Total</b>	958,085	1,020,781	93.9%

Source: Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

As noted in previous years' Performance Reviews, under an agreement with the PUCO and various parties, FirstEnergy 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 years beginning January 1, 2001. This capacity was made available on a first-come-first-served basis to competitive suppliers for committed capacity sales to FirstEnergy's customers. Of the total MSG capacity, 500 MW is reserved for residential customers. Total power allocations for the three northern Ohio FirstEnergy companies are 560 MW from Ohio Edison, 400 MW from Cleveland Electric Illuminating, and 160 MW from Toledo Edison. Prices for the capacity are based on customer class and increase each year that the capacity is made available. Industrial and commercial customer prices are the same for all three FirstEnergy 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 are \$30.03/MWh for Toledo Edison, \$31.19/MWh for Ohio Edison, and \$31.64 for Cleveland Electric Illuminating. These prices rise to \$36.28/MWh, \$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.

At this time there is only one offer being made to residential customers in one distribution company's territory, Cincinnati Gas and Electric—from Dominion Retail, Inc. No other offers are currently being made to residential customers in any other part of the state. The total number of residential offers has decreased from eight in January 2001, three in May 2002, one in 2003, and again one currently being made (July 2004).

The PUCO issued an order in June 2004 that requires a competitive bidding process to be conducted by a third party administrator for all of FirstEnergy's customer load. This is to test if there is sufficient competition among electricity suppliers to find a lower generation price than what FirstEnergy is now charging. If the bidding process does find lower generation rates, the accepted bids would determine rates offered to customers through 2008. If the bidding process does not find a lower cost supplier, then

FirstEnergy's current rates will continue and remained capped through 2008 – which extends the rate caps another three years. An annual bid will be conducted to determine if lower generation rates are available through the electricity market. The Competitive Transition Charge (CTC) will continue to be collected by FirstEnergy from consumers, which were originally set to expire at the end of 2005. The PUCO also found that FirstEnergy could only raise rates to cover any increases in taxes.

The PUCO modified this decision in August 2004 and FirstEnergy has indicated that it will implement the modified PUCO Rate Stabilization Plan. The changes include allowing an adjustment in generation rates when FirstEnergy's fuel costs increase and extending the MSG as a "backstop" if fewer than 20 percent of FirstEnergy customers are enrolled with competitive suppliers. Also part of the agreement, the competitive bid is to be conducted in December 2004 and the PUCO can end the plan with a one year's notice for any reason.

In the FirstEnergy case, the PUCO was concerned that the wholesale market had not developed sufficiently to end the rate caps as planned at the end of 2005. The Commission notes that when the state's restructuring law was passed,

. . . it was assumed that a regional market would develop quickly and that the retail markets would follow. This is why the law provided for the five-year market development period (MDP). Thus far, the electric marketplace has not developed as hoped.<sup>3</sup>

The "rate stabilization plans" filed by FirstEnergy and other Ohio utilities, are intended "to help ensure that electric consumers do not face 'sticker shock' from electric rates when the market development period ends on December 31, 2005."<sup>4</sup> The PUCO is considering rate stabilization plans for the remaining Ohio utilities that have not already had one approved.

There are informal and preliminary discussions among various interested parties in Ohio on what the next steps should be beyond the rate stabilization plans. While there

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<sup>3</sup>Public Utilities Commission of Ohio, "FirstEnergy and the End of the Market Development Period: Frequently Asked Questions," at [www.puco.ohio.gov](http://www.puco.ohio.gov).

<sup>4</sup>PUCO, "FirstEnergy and the End of the Market Development Period," *ibid*.

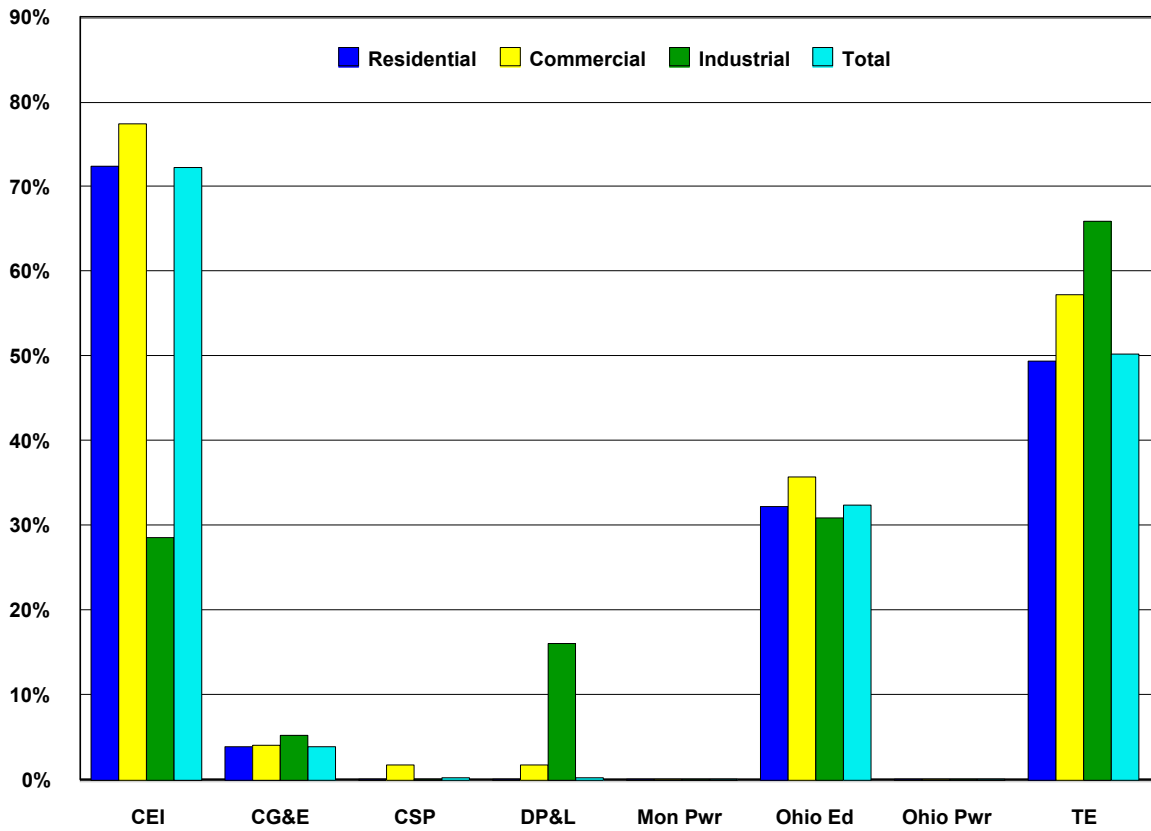
are currently no formal discussions with the PUCO or among Ohio legislators, in February 2004, the AEP companies in Ohio (Columbus Southern Power Company and Ohio Power Company) filed an application for approval of their “post market development period rate stabilization plan” that did make a recommendation to the PUCO for a formal process. AEP stated:

The [AEP] Companies believe that by the end of the Rate Stabilization Period [RSP], the competitive market for electric generation service will more closely resemble what the Ohio General Assembly envisioned, when it enacted S.B. 3, as being in place by the end of the [market development period] MDP. However, there are no assurances that such a market will exist by the end of the RSP. Therefore, it is recommended that the [Ohio] Commission conduct a proceeding to determine the manner in which electric generation service should be provided to the Companies’ customers after the conclusion of the Plan. The Commission should consider various options ranging from a ‘flash cut’ completion of the transition to competition, to returning to traditional cost-of-service regulation. It is further recommended that the Commission complete and report the results of this proceeding to the Ohio General Assembly no later than December 31, 2005 so that sufficient time will be available for the consideration and enactment of any legislation which might be needed. The report would include recommendations to the General Assembly. Before making such recommendations, the Commission should provide an opportunity for input by all interested parties.<sup>5</sup>

This reflects a general view among many in the state that more formal discussions are necessary to consider possible needed changes to the state’s restructuring law, in view of the less than favorable market conditions (for consumers) that could persist through the end of 2008, when the rate stabilization plans expire. This also reflects the view of some that significant modification or even a reversal of the restructuring course may be necessary.

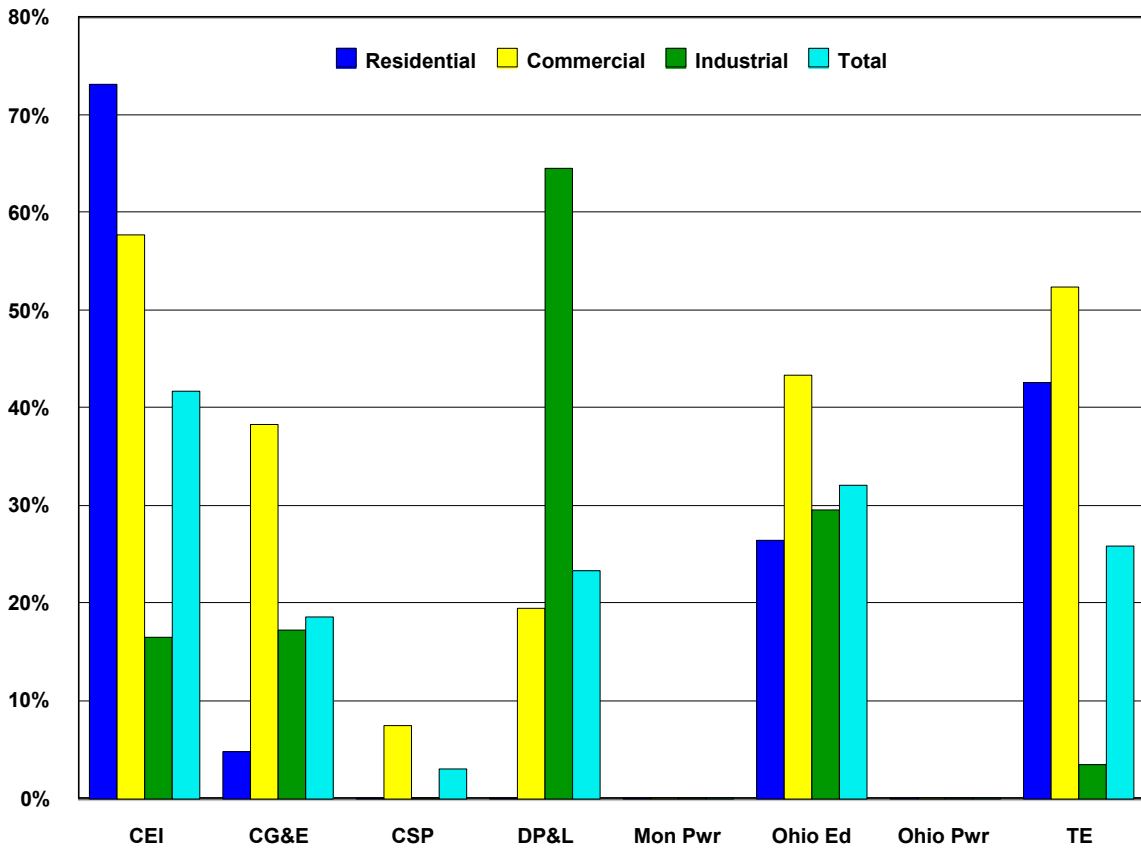
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<sup>5</sup>“In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post Market Development Period Rate Stabilization Plan,” Case number 04-169-EL-UNC, PUCO file date February 9, 2004; from item number 8 on pages 13 and 14.



**Figure V.4.** Percent of customers that switched to alternative electric suppliers, March 2004.  
 Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.





**Figure V.5.** Percent of megawatt-hour sales that switched to alternative electric suppliers, March 2004.

Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

The following is a summary of the Stipulation and Recommendation entered into by FirstEnergy and several interest groups that became the settlement accepted by the PUCO to implement restructuring in northern Ohio.

## **Summary of Transition Costs Treatment in the FirstEnergy “Stipulation and Recommendation”**

### Terms used in the Stipulation and in this summary:

RTC: Regulatory Transition Charge; charge to customers for unrecovered regulatory costs associated with regulatory assets, such as deferred expenses.

GTC: Generation Transition Charge; charge to customers for generation costs deemed to be uneconomic or unrecoverable in a competitive generation market.

Transition Costs: The term used and defined in S.B. 3 (restructuring legislation) to refer to costs incurred by regulated utilities to serve their customers that may not be recoverable in a competitive market. Also called “stranded costs ” and includes regulatory and generation costs.

Generation or “little g”: The determined economic generation plant, or what was determined to be recoverable in the market. For the FirstEnergy companies, this was calculated for unbundling purposes only and not used to calculate the “Shopping Credits.”

Discount: A 5 percent discount off the generation cost mandated by S.B. 3. Calculated in the Stipulation as 5 percent of the sum of generation (“little g”), the RTC, and the GTC, or “Big G.”

Market Development Period: January 1, 2001, the beginning of retail access, to December 31, 2005.

Shopping Credit: The “credit” back to a customer if they purchase power from another supplier. The shopping customers’ new price for generation is then the price they pay their new supplier. The shopping credit is the amount that the customer uses to compare competitive offers, or the “price-to-compare.”

MSG: Market Support Generation; the 1,120 MW of generating capacity made available by the three FirstEnergy companies (Ohio Edison, Cleveland Electric Illuminating, and Toledo Edison) to non affiliated marketers, brokers, or aggregators (not affiliated with any Ohio investor-owned utility) for sales to retail customers during the market development period, as allocated by company and customer class in the stipulation.

MSP: Market Support Price; the price for MSG as set in Attachment 2 in Megawatt hours.

Shopping Credit Incentive: Percentage used to calculate the shopping credit during the Market Development Period, from Attachment 3, and is based on the fixed MSP.

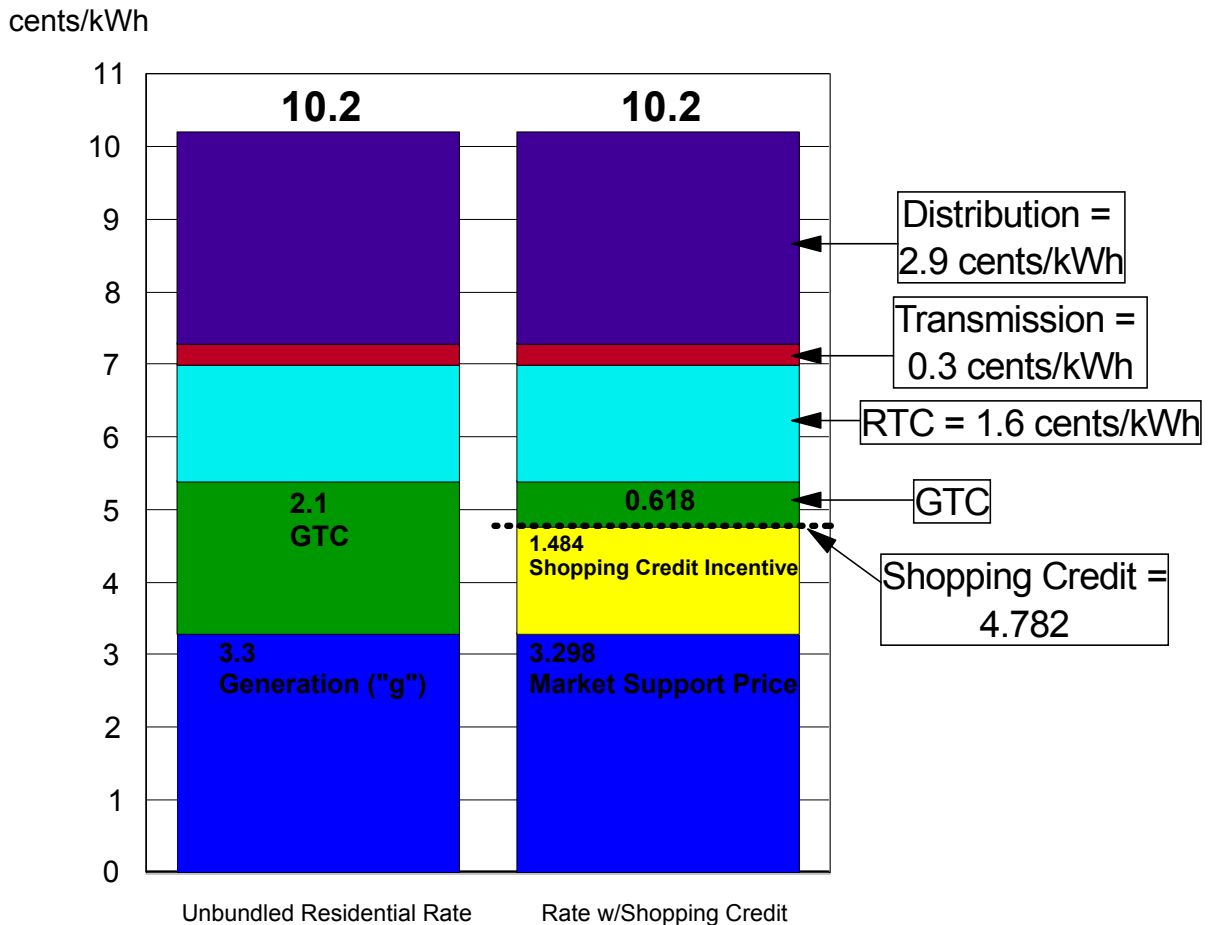
#### A Numeric Example

Figure V.6 below was drawn using the 2002 average unbundled rate components for Ohio Edison's residential class customers provided by the PUCO staff and the 2002 Shopping Credit with Incentives found in Attachment 3 of the FirstEnergy "Stipulation and Recommendation" for the same company and customer class. This is intended to be an illustrative example, not the exact amount residential customers in Ohio Edison's territory actually pay. The actual rates are divided by subclass (residential standard, residential space heating, etc.), the season (winter, summer), usage (amount of kWhs used), customer charges (a fixed charge that varies by subclass), and year applied. This is the situation for the market development period that began January 1, 2001 and continues through December 31, 2005.

The first column in Figure V.6 is the unbundled rate for residential service. The charge for distribution and transmission are fixed, but can be altered under certain circumstances—adjusted for Regional Transmission Organization (RTO) participation costs, for example. The RTC charge, or the Regulatory Transition Charge, to recover regulatory assets extends beyond the Market Development Period and may also be adjusted over time. The GTC in the first column is the fully allocation charge for uneconomic generation. Paid out over time and with no customer switching to alternative suppliers, this would allow the company to recover past generation costs that

were believed to be unrecoverable in a competitive market. The generation portion, or “little g,” is the generation cost that could be recovered in the market or the “economic plant.”

For customers that do not choose an alternative supplier and remain with their utility, in this example they pay the total bundled price of 10.2 cents per kWh. A customer that chooses an alternative supplier pays the same unbundled rates, as shown in the second column, for distribution, transmission, and RTC, but the generation price is now the new supplier’s price. If a customer can find a price below the “Shopping Credit,”



**Figure V.6.** Numeric example of FirstEnergy “Stipulation and Recommendation” mechanism.  
 Source: authors construct from the term of the agreement and PUCO staff numbers.

in this example, below 4.782 cents per kWh, the customer's savings would be the difference between the shopping credit and the new price for generation. For example, if a customer purchased power for four cents per kWh, they would save 0.782 cents per kWh and would pay a total bundled price of 9.418 cents per kWh.

For FirstEnergy, for customers that remain with them, they collect the entire GTC along with all the other charges (column one in the figure). For customers that switch to an alternative supplier for their generation, FirstEnergy now collects the reduced GTC plus the same RTC and the transmission and distribution charges. The difference between the market support price and the shopping credit, or the shopping credit incentive as shown in yellow in the figure, is deferred for recovery past the end of the market development period and is to be recovered as an adjusted RTC. Specific dates are set for each company for when the RTC recovery period should end, unless additional time is needed to amortize the deferrals when more than 20 percent of any customer class by company has switched or from a "substantial deviation" in the estimated sales due to changing economic conditions.

The legislative mandated 5 percent discount is calculated based on the generation component ("little g"), the RTC and the GTC (together referred to as "big G"). The total rate shown in Figure V.6 has the discount already deducted.

There is also a "Transition Cost Recovery Incentive" that would reduce the period of recovery of the RTC for up to \$500 million if a class of customers by company has not reached 20 percent by the end of the market development period. Amounts by company and other details are in the Stipulation.

## **Section VI SOUTH AND SOUTHEAST**

### **Wholesale Markets in the South and Southeast**

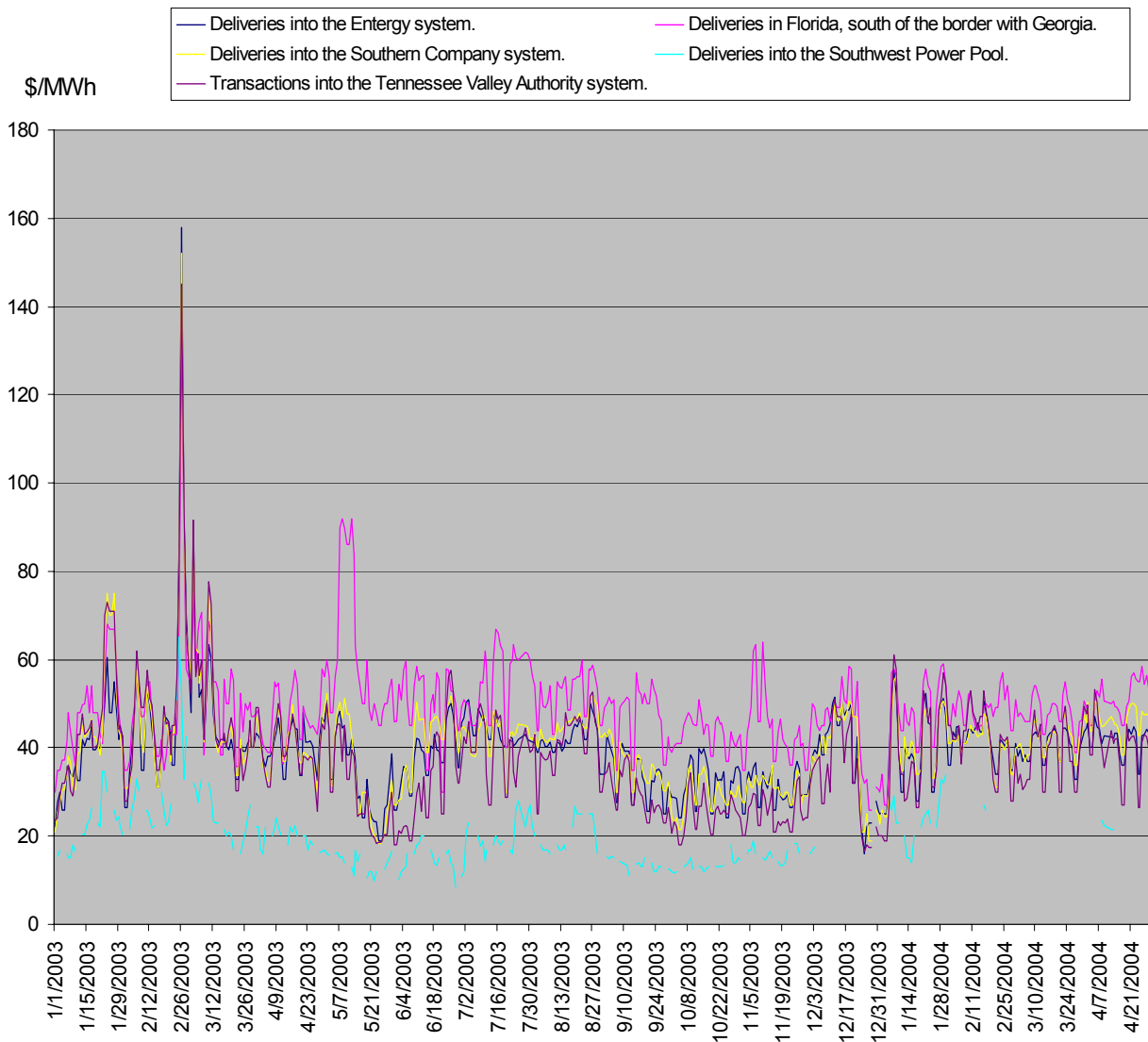
There are no operational ISOs or RTOs in the southeast region at this time. Three RTOs have been proposed over the last several years. In 2000, Progress Energy (Carolina Power & Light), Duke Energy, and SCANA began the formation of GridSouth RTO and filed a plan with FERC to operate the RTO in the North and South Carolina region. FERC later encouraged and mediated discussions with other southeastern transmission organizations to create a single regional RTO. However, due to a lack of consensus on which model to follow for the region, GridSouth suspended its implementation activities in June 2002.

Transmission owners in Alabama, Florida, Georgia, Mississippi, and South Carolina (including the region's largest transmission owners, Entergy and Southern Company) began the formation of the SETrans RTO in 2001. However, also citing a lack of consensus and support in the region, development activity on the RTO was suspended in December 2003, which was decided unanimously by the sponsors.

Also in 2000, Florida Power & Light, Progress Energy (Florida Power Corp.), and Tampa Electric Company, formed GridFlorida and filed with FERC to become an RTO. Provisional RTO status was granted by FERC in March 2001, provided GridFlorida continued to discuss interregional coordination with neighboring transmission organizations. Due to objections by the Florida Public Service Commission, GridFlorida refiled with FERC to become a not-for-profit entity in December 2001. Discussions between GridFlorida, FERC, the Florida PSC, and other interested parties continued into late 2003.

While there are no functioning ISOs or RTOs in the region, there are wholesale transactions for power delivered into the major companies and areas in the region. Figure VI.1 graphs *Megawatt Daily's* volume weighted-average (peak hour) price indices for five areas in the south and southeast region, for deliveries into Entergy, Southern Company, Tennessee Valley Authority, Florida, and the Southwest Power Pool. This

covers a wide and diverse area, which may explain the disparity between the higher prices into Florida (with relatively higher generation costs in the region) versus the lower prices for the Southwest Power Pool. As seen in other regions, all five price indices responded to the spike in natural gas prices seen in early 2003 (the natural gas price spike in early 2004 was mainly limited to the northeast, as seen in the New York prices in Figure I.3 of Section I).



**Figure VI.1.** Daily weighted-average wholesale power prices in the southeastern region. Data Source: Platts, *Megawatt Daily*.

A case currently before the Georgia Public Service Commission and FERC has important implications for both the region and FERC policy on utilities' ability to use their ratepayers to hedge their competitive risks. The case before the Georgia PSC is a request by Southern Company's two Georgia utilities to recover \$563 million for the cost of two power units outside Savannah.<sup>1</sup> The two McIntosh gas-fired units are still under construction and are located next to an existing coal-fired plant. FERC has been investigating alleged bidding irregularities by Southern Company, its two Georgia utility affiliates, and Southern Power, an affiliated wholesale power company that sold the two McIntosh units to Georgia Power and Savannah Electric in May 2004. Southern Power, the Southern Company subsidiary, began building the units after winning a competitive bid in late 2001 to sell wholesale power to Georgia Power and Savannah Electric.

The state PSC approved the purchased-power contracts in 2002. Southern Co. then submitted them to the FERC for approval. But competitors challenged the contracts, arguing that Southern Company used overlapping affiliates to favor Southern Power and asked FERC to reject the contracts. Competitors and FERC staff found evidence that Southern Company had been, at best, "sloppy" about conflicts of interest and had provided its own bidder with advantages.

The Georgia PSC decided to allow Georgia Power and Savannah Electric to buy the plants from Southern Power and recover the cost from ratepayers, but will decide later the dollar amount to be recovered. The PSC is also considering new rules on bidding for purchased power and transactions between affiliates. Southern Company canceled the Southern Power contracts and withdrew its application for FERC's approval a week before a hearing was to begin. While the sale of the units would take them out of FERC's control and transfer them to the Georgia PSC, FERC staff recommended that the investigation of Southern Company's bidding behavior continue. In addition, in a rate case, Georgia Power is seeking its first rate increase in 13 years.

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<sup>1</sup>The facts of the pending cases were primarily from "Georgia Power Users Could Foot Big Bill," by Margaret Newkirk, *The Atlanta Journal-Constitution*, June 12, 2004, distributed by Knight Ridder/Tribune Business News.



## **Retail Markets**

While several states in the southeast have studied whether to adopt retail access or had legislative proposals, no state in the region has adopted retail access and there are currently no formal actions to do so.

## **Section VII TEXAS**

Due to the apparent early success of its retail markets, Texas has attracted a great deal of attention across the country. Since its beginning in January of 2002, the Texas retail market has been one of the more active in terms of offers to residential customers and savings opportunities. This early success has led some to proclaim Texas as the model for both its retail access program and its wholesale market design. This section is an abbreviated version of last year's (2003) Performance Review of the Texas market, with updated information on wholesale prices, customer switching, and residential choices.

### **Wholesale Market and the Electric Reliability Council of Texas**

The Electric Reliability Council of Texas, Inc. (ERCOT) administers Texas' power grid and serves approximately 85 percent of the state's electric load, an area that includes about twelve million people. ERCOT is an independent, not-for-profit organization responsible for the transmission of electricity and is one of ten regional reliability councils in the North American Electric Reliability Council (NERC). ERCOT has approximately 78,000 megawatts of generation and over 37,500 miles of transmission lines. ERCOT covers approximately 75 percent of the land area in Texas.

The Texas Public Utility Commission (the Commission or Texas PUC) has primary jurisdiction over ERCOT activities and, because ERCOT is located completely within the borders of a single state, FERC does not have any jurisdiction. Some believe that this provides Texas with a better opportunity to coordinate the ERCOT portion of the state's retail and wholesale markets since both are state jurisdictional and the FERC is not involved. Outside of the ERCOT region, transmission access and pricing and wholesale generation markets are under the jurisdiction of the FERC. Retail pricing and market operations remain under the jurisdiction of the Texas Public Utility Commission.

In May 1999, the Texas Legislature passed a bill to allow electric choice or retail access, which began for most consumers in January 2002. This required ERCOT to change its structure and functions. ERCOT is still responsible for transmission reliability and open wholesale access, but is also charged with overseeing the transactions related to the state's restructuring of the electric industry—including the development and operation of the ERCOT portion of Texas' competitive retail market.

ERCOT's market relies primarily on bilateral contracts between buyers and sellers of electricity traded. In contrast to other markets in the U.S. where there is either a central power exchange or sizable day ahead and/or real-time markets that are administered by the independent system operator. Two concerns the Commission has expressed with having such reliance on the bilateral market are price discovery and liquidity.<sup>1</sup> A broader market, they note, could provide greater liquidity and price transparency, and provide better information about future supply and demand conditions. The existing market design, they claim, also presents gaming opportunities for market participants that could probably be eliminated by redesigning the market.

### ERCOT Market Operations<sup>2</sup>

As noted, ERCOT's wholesale market is a market where participants use bilateral forward contracts almost exclusively, with zonal congestion management and a system operator running a minimal real-time balancing market. The Market Oversight Division of the Texas Public Utility Commission noted that ERCOT is the only operating ISO/RTO-based wholesale market in the U.S. that uses only bilateral forward contracting among market participants. ERCOT's residual energy market for balancing

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<sup>1</sup>Public Utility Commission of Texas, Report to the 78<sup>th</sup> Texas Legislature, "Scope of Competition in Electric Markets in Texas," January 2003. Much of the details about the Texas markets, unless otherwise indicated, are from this Texas Commission report and from various ERCOT sources.

<sup>2</sup>A useful overview of ERCOT market operations is "The Market Guide: An introductory guide to how the Electric Reliability Council of Texas (ERCOT) facilitates the competitive power market," January 1, 2004.

energy, representing five percent to ten percent of total demand, is for the reliability of the Texas electric grid. The Texas Commission has identified problems with its wholesale market design and has been formally considering changes.

In 2003, the Texas PUC (Order 26376) began a redesign of how the wholesale market manages transmission congestion and provides "day-ahead" market services. A "Nodal Team" of market stakeholders was established in August of 2003 to begin the redesign of the zonal congestion management system to a Local Marginal Pricing (LMP) or "nodal" model. The PUC order is to be implemented by the end of 2006.

Prices in the bilateral market that represents the bulk of delivered energy in Texas are based on mutual agreement or long-term contract between the parties, and are not known by ERCOT. These agreements are incorporated into base energy schedules which are submitted to ERCOT on a daily basis and account for over 90 percent of the end-user electric energy requirements in ERCOT.

#### Ancillary Services

ERCOT has operated day-ahead ancillary service markets and the real-time balancing energy market since July 31, 2001. ERCOT's five ancillary services (and the total amount required each day) are: Regulation Up (1,200 MW), Regulation Down (1,800 MW), Responsive (spinning) Reserves (2,300 MW), Non-Spinning Reserves (1,250 MW), and Replacement Reserves (as needed). Market participants can self-provide their ancillary service requirements or allow ERCOT to procure these services on their behalf.

During the first year of operation as a single control area, ERCOT usually procured from ten percent to 20 percent of the ancillary service capacity required. Market participants chose to provide their own ancillary services rather than expose themselves to unknown market clearing prices from the ERCOT auction. According to the Commission (in 2003), prices for ancillary services procured by ERCOT were below \$20 per MW for more than 95 percent of the time, from August 2001 through July 2002.

## Capacity Adequacy

ERCOT currently has no formal capacity market comparable to PJM's capacity credit market. The Texas Commission is developing a generation adequacy rule which likely will use a mechanism that differs from capacity credit markets in the northeast region of the U.S. ERCOT utilities have traditionally sought to maintain a planning reserve margin of 15 percent. Because the system cannot rely on imports, due to its isolation from surrounding interconnections, relatively high reserve margins are thought necessary. However, in mid-2002, the ERCOT Board approved a 12.5 percent reserve margin requirement.

In 2000 and 2001, the reserve margins at peak were 14 percent and 21 percent, respectively. From 1995 to January 2001, 22 new generating plants, totaling more than 7,600 MW, were built in the ERCOT region. This represents 10.9 percent of total generating capacity; during this same period, peak demand grew by 24.5 percent. The Texas Commission reports<sup>3</sup> that statewide (ERCOT and non-ERCOT regions of the state) 68 plants for a total of 29,375 MW were completed from 1995 through early 2004. Also, it was reported that 6 plants with a total of 2,483 MW were under construction, 14 plants with a total of 7,108 MW had been announced or planned, and 15 plants totaling 8,212 MW had been delayed. The Commission indicated that 7,349 MW of announced new generation capacity had been cancelled, 7,296 MW had been "mothballed," and 1,211 MW were retired. Of the completed capacity additions, wind turbines accounted for 1,260.5 MW of the projects, while the remaining 28,114.5 MW were nearly all natural gas combined cycle plants. The Texas Commission is reporting an expected ERCOT capacity reserve margin of 27.1 percent for 2004 and a 23.8 percent expected reserve margin for 2005.<sup>4</sup> By 2008, the current expectation is for it to decline to 17.3 percent.

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<sup>3</sup>These data on generating plant project status are from "New Electric Generating Plants in Texas Since 1995," April 15, 2004.

<sup>4</sup>Public Utility Commission of Texas, presentation before Senate Business and Commerce Committee, "State of the State –A Brief Review of Electric Competition," April 27, 2004.

The Commission noted that transmission constraints limit the deliverability of some generation resources, especially wind power from West Texas. The Commission states that so much wind power has been added that the existing transmission system is not always capable of delivering all of the power available from the wind projects. Transmission projects are planned to relieve the bottlenecks, but they report that significant new facilities are required, which will take up to five years to complete.

ERCOT introduced monthly and annual Transmission Congestion Rights (TCRs) auction markets in February of 2002. TCRs were implemented in ERCOT along with the implementation of direct assignment of interzonal congestion charges to allow market participants a means to offset the risk of transmission congestion charges. ERCOT initially adopted a simple flow-based transmission right approach and flow-based congestion charges. An annual auction is held for 60 percent of the TCRs, the remaining 40 percent are auctioned on a monthly basis.

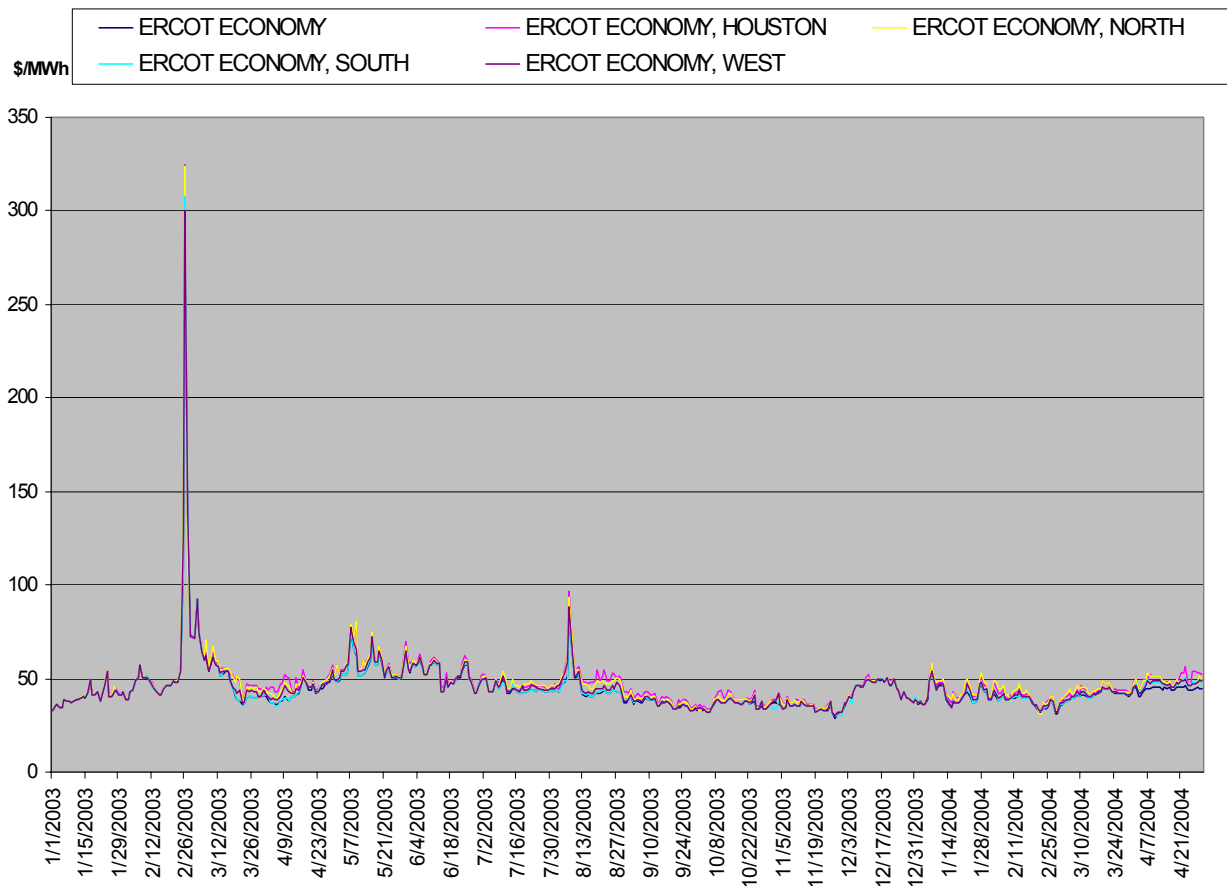
#### Real-Time Balancing Energy Market

As noted, ERCOT does not have a central power exchange or sizable day ahead or real-time energy markets administered by an independent system operator. However, ERCOT does have a balancing energy market designed to maintain the balance between load and generation and to resolve transmission congestion. Balancing energy makes up the difference between the total ERCOT electricity requirements and the sum of the base energy schedules. The real-time balancing energy market process accepts bids in ascending order of price until the total quantity required is obtained. The bid price of the last quantity accepted for Balancing Energy Service sets the Market Clearing Price of Energy (MCPE) for that 15-minute interval.

The balancing energy market is not a spot market, but an ancillary service market, and accounts for only five to ten percent of the total ERCOT energy market.

#### Market Prices

Figure VII.1 shows the ERCOT energy spot market prices for the five trading zones, as reported in *Megawatt Daily*. These are volume-weighted average daily price



**Figure VII.1.** Daily volume weighted average price indices (\$/MWh) for ERCOT trading zones.  
 Data source: Platts, *Megawatt Daily*, January 2003 through April 2004.

indices for the trading zones. Being an interconnected region, the ERCOT zone prices move together in a relatively tight range. There was a considerable price spike that occurred in early 2003, when prices reached \$300 per MWh or more in four of the zones (the peak was \$325 per MWh for the Houston zone). Another spike occurred in the summer of 2003 to nearly \$100 per MWh. Prices traded mostly in the \$40 to \$50 per MWh range or higher for most of March and April of 2004.

## Texas Retail Market

### Overview

As noted, Texas passed their restructuring bill in June of 1999 and retail competition began for all customers of investor-owned utilities in the Electric Reliability Council of Texas (ERCOT) region on January 1, 2002. For areas served by municipal utilities and electric cooperatives, competition is allowed if the governing body of the city or cooperative opts for retail competition. Metering services for commercial and industrial customers opened to competition beginning January 1, 2004. For residential customers, metering services are regulated until September 1, 2004 or until 40 percent of customers have switched to an alternative supplier, whichever is later.

The Legislature delayed retail competition for utilities in the non-ERCOT regions of Texas, in the El Paso Electric service area until September 2005, (the end of the rate-freeze period from El Paso Electric's bankruptcy proceeding in 1995) and in the Southwestern Public Service Company service area (in the Panhandle region of Texas) until 2007 at the earliest. The Southwestern Public Service Company service area is described as a transmission-constrained area that has limited access for alternative power generation companies and retail providers to serve customers.<sup>5</sup> The Public Utility Commission of Texas delayed the start of full customer choice for the Entergy, Southwestern Electric Power Company (SWEPCO – the Commission suspended full customer choice until January 2007 for SWEPCO), and a small portion of West Texas Utilities Co.'s (WTU)<sup>6</sup> service area that is located within the Southwest Power Pool region. The Commission delayed competition for the Entergy and SWEPCO service areas because of three concerns: (1) a lack of independence in the administration of transmission service and uncertainty about the market rules for these areas; (2) a lack

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<sup>5</sup>The Legislature required Southwestern Public Service Company to conduct an analysis on the need for additional transmission infrastructure and on plans to interconnect with other power regions.

<sup>6</sup>WTU is now also known as AEP Texas North, an affiliate Retail Electric Provider (REP) of AEP's Texas local distribution utilities. AEP Texas Central, also is still known by its former names CPL, Central Power and Light Company, or CPL Retail Energy.



of testing of the technical systems needed to accommodate retail choice; and (3) a lack of necessary market institutions and lack of open and non-discriminatory access to the transmission grid.

Investor-owned utilities were required to separate their business functions into three distinct companies: a power generation company (PGC), a transmission and distribution utility (TDU), and a retail electric provider (REP). PGCs operate as wholesale providers of generation services, such as independent power generators. REPs operate as retail providers of electricity and energy services and have primary contact with retail customers. TDUs remain regulated by the Commission, and are required to provide non-discriminatory access to the transmission and distribution grid at rates and terms of access prescribed by the Commission.

#### The “Price-to-Beat”

Customers who did not choose a new retail electric provider, or REP, by January 1, 2002 were automatically transferred to their utility’s affiliated REP. Residential and small non-residential electric customers (with a peak demand of 1 MW or less) who remain with the affiliated REP are charged a regulated rate, called the “price-to-beat.” Commission rule generally required a 6% reduction from the rates in effect on January 1, 1999 for residential and small commercial customers, with adjustments for the setting of a final fuel factor for the integrated utility as of December 31, 2001. The reduction applied to customers who did not choose a REP and continue to take service from the affiliated retail electric provider. The affiliated REPs are required to sell electricity at the price-to-beat until January 1, 2007.

Texas purposefully set the price-to-beat with some “headroom,” that is, to allow the difference between the price-to-beat and the costs incurred by non-affiliated REPs (see the discussion in the overview section of this report) to be sufficient to allow competitors to profitably offer prices to customers for their services and offer sufficient savings off the price-to-beat so that customers are encouraged, by the potential savings, to consider alternative suppliers. The Commission found, as other states have, that if the price-to-beat or the fuel factors were not adjusted to reflect changes in the

market price of electricity, the price-to-beat could fall below the costs of alternative REPs and competition in the retail market will not develop and decline (negative headroom). For this reason, the price-to-beat is adjusted to reflect changes in natural gas and purchased energy market prices. If the price of natural gas futures changes by more than four percent, Commission rule permits the affiliated REP to request adjustments to their fuel factor. Also, if headroom diminishes from changes in the market price of purchased power as measured by one-year and three-year contract prices, the affiliated REP may also request an adjustment to the price-to-beat.

Affiliated REPs, that is, the incumbent utility, can offer rates lower than the price-to-beat beginning January 1, 2005, or earlier if at least 40 percent of residential or small-commercial customers switch to competitors.

The price-to-beat rates for residential customers for each affiliated REP are shown in Table VII.1. In the case of First Choice/TNMP, CPL/Mutual Energy, and WTU/Mutual Energy, base rates changed a level other than six percent due to changes in rates between January 1, 1999 and December 31, 2001 that resulted from merger proceedings. (See the sideline note on company names in Texas.) Since retail access began on January 1, 2002, the Price-to-Beat has increased significantly for all the companies – by 22 percent, 28 percent, 23 percent, 30 percent, and 34 percent for TXU, Reliant/CenterPoint, First Choice/TNMP, CPL/Mutual Energy, and WTU/Mutual Energy, respectively.

**Table VII.1.** Price-to-Beat rate comparison (cents per kWh).\*

<b>Affiliated REP</b>	<b>Dec. 31, 2001</b>	<b>Jan. 1, 2002</b>	<b>Sept. 2002</b>	<b>June 2003</b>	<b>May 2004</b>
<b>TXU</b>	9.67	8.25	8.66	9.70	10.06
<b>Reliant/CenterPoint</b>	10.40	8.62	9.12	10.10	11.05
<b>First Choice/TNMP</b>	10.57	8.66	9.15	10.10	10.65
<b>CPL/Mutual Energy</b>	9.57	8.80	9.52	10.92	11.42
<b>WTU/Mutual Energy</b>	9.98	8.88	9.73	11.34	11.91

\*May 2004 Price-to-Beat for 1,000 kWh.

Source: Public Utility Commission of Texas, January 2003 and May 2004, ENERGYguide.com, June 2003.

The Commission reports that because of significant increases in the price of natural gas, the fuel factor portions of the rates have been rising significantly and also required fuel surcharges to recover past uncollected fuel expenses. At the end of 2001, natural gas prices had fallen significantly, resulting in reductions in the fuel factor portion of the price-to-beat rates. Also, the fuel surcharges that were in place during 2001 terminated in December 2001. As a result, customers received in excess of a six percent reduction in their total rates as compared to rates in effect on December 31, 2001. Natural gas prices dropped in the early months of 2002, but began to rise significantly in March and April of 2002. All of the affiliated REPs (except TXU-SESCO)

subsequently requested adjustments to their price-to-beat fuel factors in order to reflect increases in the price of natural gas in the range of 16 percent to 24 percent. Reliant Resources filed for a second adjustment in November 2002 to reflect a further seven percent increase in natural gas prices (that was approved by the Commission in December 2002).

#### Provider of Last Resort (POLR) Service

In areas of the state where retail access is in effect, the Commission designates REPs to serve as providers of last resort or a POLR. The Commission adopted POLR rules in October 2000 that required the selected POLR to charge a fixed rate that could

Due to mergers; the required unbundling of investor-owned utilities into three companies – (1) power generation company (PGC), (2) transmission and distribution utility (TDU), and (3) retail electric provider (REP); and other structural changes that companies in Texas have undergone in recent years, the names of companies have been changed or new names created. In this report, where possible, the names of the companies reported by the Commission along with the figures supplied are used in the tables and graphs. In the text, the company's pre-retail access utility name is also given. Here is a summary of the utility, REP, or new names that are used:

- Central Power and Light Co. / CPL / AEP Texas Central / now CPL or Mutual Energy
- HL&P / Reliant Energy / CenterPoint Energy
- Texas-New Mexico Power Co. / TNMP / First Choice Power
- TXU Electric & Gas / Oncor
- West Texas Utilities Co. / WTU / AEP Texas North / now WTU or Mutual Energy.

not be changed over the term of the POLR contract. Each POLR was required to offer a standard retail service package for each class of customers designated by the Commission at the approved fixed, non-discountable rate. In the event that a REP failed to serve its customers, the POLR must offer the standard service package to those customers with no interruption of service. The standard service package must also have been available to any requesting customer. In addition, under the original POLR rule and customer protection rules, only the POLR had the authority to disconnect customers for nonpayment of electric services. Other REPs could only cancel a nonpaying customer's contract and transfer that customer to the POLR.

POLRs were originally to serve two types of customers: (1) customers of a REP that chose to exit the market without making arrangements to transfer those customers to another REP, and (2) non-paying customers of a REP. For the first set of customers, POLRs faced the risk of potentially being required to serve a large number of customers from an exiting REP with little notice and at a fixed rate that was set far in advance of the switch. For the second set of customers, POLRs faced the risk of serving customers that had already demonstrated an inability or unwillingness to pay their provider for energy consumed. The Commission states that the combination of these risks led to the high rates initially set for the POLRs for 2002. Several parties appealed the orders and contracts with the POLRs alleging that the rates were not just and reasonable, and that the Commission erred in the process it used to select POLRs and set the rates for POLR service.

The Commission's new POLR rules remove non-paying customers from the class of customers served by the POLR. REPs no longer transfer non-paying residential and small commercial customers to the POLR, as of September 2002. Instead non-affiliated REPs transfer them to the affiliated REP for service at the price-to-beat. The affiliated REP has authority to disconnect the customers if the customer does not establish any required deposit with the affiliated REP, or subsequently does not pay a bill of the affiliated REP. All REPs have authority to disconnect large commercial and industrial customers for non-payment, unless an existing contract provides for different treatment.

This structure will remain in place until October 1, 2004. After that, all REPs will have the authority to disconnect non-paying customers, if protections are in place for retail customers. The primary purpose of the POLR service is now to serve customers of a REP that exited the market without making arrangements to transfer their customers to another REP.

The original POLR rules chose a sealed-bid competitive bidding process to set the POLR rates. The Commission conducted a bid for each customer class in each designated service area, but only one REP submitted a bid. The Commission accepted the bids of TXU Energy Services to provide POLR service in the majority of the state. The Commission designated non-bidding REPs to serve as POLRs and set the rates for the remaining areas of the state where no bid was received through negotiation and in contested case proceedings. The initial rates for POLR service, whether approved by bid, negotiation, or contested case proceeding, were substantially above the price-to-beat in all areas.

Under the revised POLR rules, the Commission compares bids for POLR service on price alone and the selected rates are to be adjusted monthly to reflect changes in wholesale market prices. If no bids are submitted or all bids are rejected, the new rule requires the Commission to select POLRs by a lottery. The selected POLRs would provide service at specific rate levels determined under the rule. For service beginning January 1, 2003, only affiliated REPs were eligible to bid or be selected by lottery. Bids could also not exceed 125% of the price-to-beat for residential and small commercial customers.

The Commission noted that the competitive process it envisioned has yet to perform adequately. Only Reliant Resources submitted a POLR bid under the new process and was selected as POLR for most areas of the state. TXU Energy Services, First Choice Power, and AEP did not submit bids under the revised rule. The Commission held a lottery for the areas where Reliant did not bid.

The 2002 and 2003 POLR rates for Texas service areas are in Table VII.2.

**Table VII.2.** POLR rates for 2002 and 2003 (cents per kWh).

<b>Service Area</b>	<b>2002 POLR Rates</b>	<b>2003 POLR Rates</b>
<b>Reliant/CenterPoint</b>	11.96	10.83
<b>TXU/Oncor</b>	10.54 - 11.05	10.00
<b>WTU/AEP Texas North</b>	12.86	12.37
<b>CPL/AEP Texas Central</b>	12.22	11.08
<b>TNMP/First Choice Power</b>	12.13	10.99

Source: Public Utility Commission of Texas, January 2003, p. 44.

### Customer Choices

Texas continues to have the most active market in the country for residential customers in terms of offers and savings opportunities. In May 2004, as summarized in Table VII.3, residential customers had between six to ten competitive providers offering between eight to 14 competitive offers (this count does not include the affiliated REP's standard service at the price-to-beat rate). All five areas have at least seven offers below the price-to-beat rate, two areas had seven offers, and three areas had eight offers below the price-to-beat. As measured by the lowest offer, residential customers had an opportunity to save between ten percent and 22 percent off the price-to-beat rate.

According to the Texas Commission, reporting in early 2003, commercial and industrial customers also appear to have a large variety of offers from which to choose. They report that there were, as of September 2002, approximately 19 REPs serving commercial and industrial customers in all service territories open to competition. As seen in other states, while residential offers are sometimes publicly available, the commercial and industrial market operates mostly under individual contracts. These customers often negotiate the type of service (firm vs. interruptible, short term vs. long term), and choose the amount of risk of price volatility (fixed price vs. indexed) they desire to accept. Customers who have negotiated contracts with the pricing tied to natural gas or power market prices enjoyed extremely low prices early in 2002 when

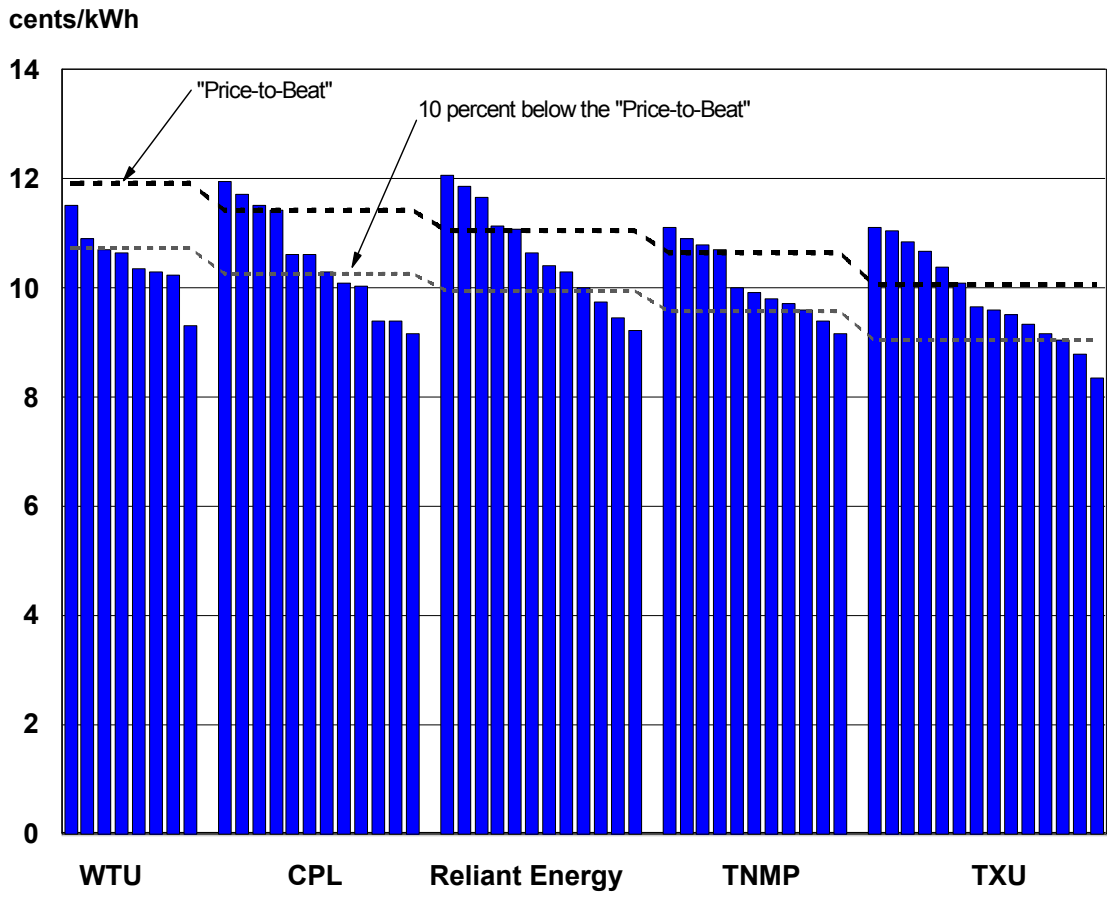
natural gas prices (and power prices) dropped dramatically. Customers who have negotiated fixed price contracts have been able to avoid the subsequent increase in prices that have occurred since.

**Table VII.3.** Residential competitive offer summary for Texas, May 2004

<b>Utility</b>	<b>Number of Competitive Suppliers</b>	<b>Total Number of Offers from Competitive Suppliers</b>	<b>Number of Offers Below the Price-to-Beat</b>	<b>Savings with Best Offer*</b>
<b>TXU/Oncor</b>	10	14	8	17%
<b>CPL/Mutual Energy</b>	8	12	8	20%
<b>WTU/Mutual Energy</b>	6	8	8	22%
<b>Reliant/CenterPoint</b>	10	12	7	17%
<b>TNMP/First Choice Power</b>	7	11	7	10%

\*Calculated by comparing the Price-to-beat with the lowest offer in cents/kWh. Data Source: Public Utility Commission of Texas, based of offers from ENERGYguide.com.

Figure VII.2 graphs all the residential offers in five service territories that were made in late May 2004 (the same offers tallied in Table VII.3). All service areas had offers below the price-to-beat (heavy dashed line in figure) and also at or greater than ten percent savings (dotted line in figure).

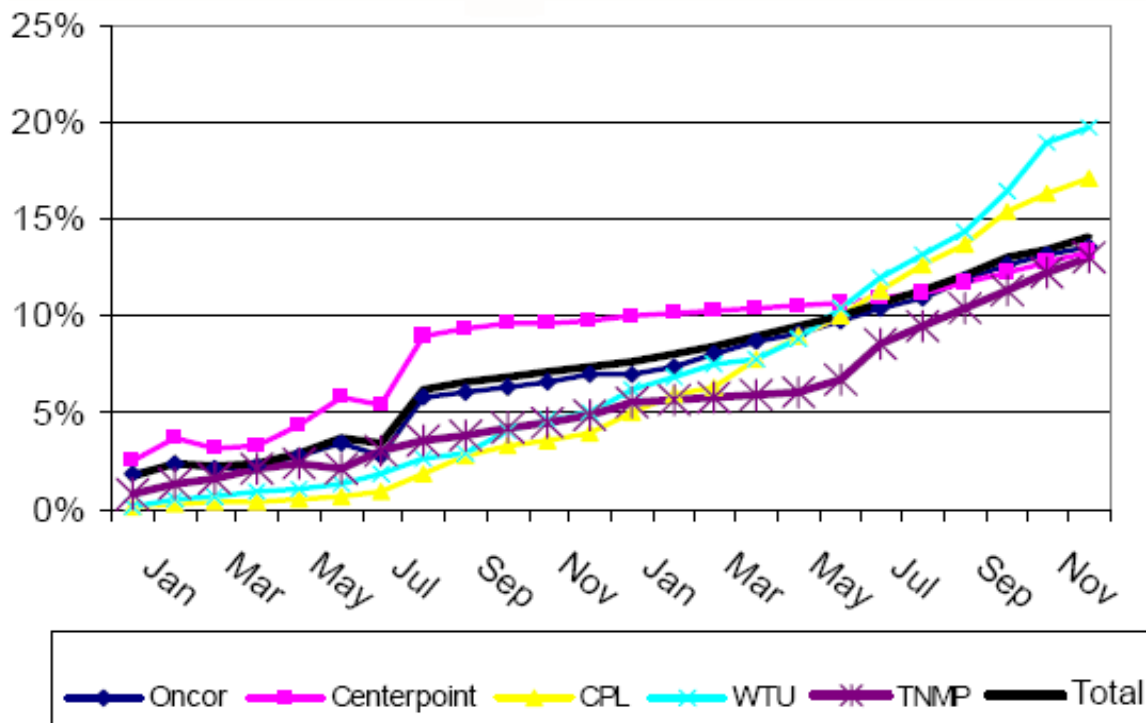


**Figure VII.2.** Residential offers in five Texas service territories, May 2004. Data Source: Public Utility Commission of Texas, based of offers from ENERGYguide.com.

Customer Switching

As Figure VII.3 shows, almost 15 percent of all residential customers were served by a non-affiliated REP by December 2003. All service areas had over ten percent of residential customers being served by non-affiliated REPs by the fall of 2003. WTU reached almost 20 percent by the end of 2003. Figure VII.4 shows that about 28 percent of CPL secondary voltage customers

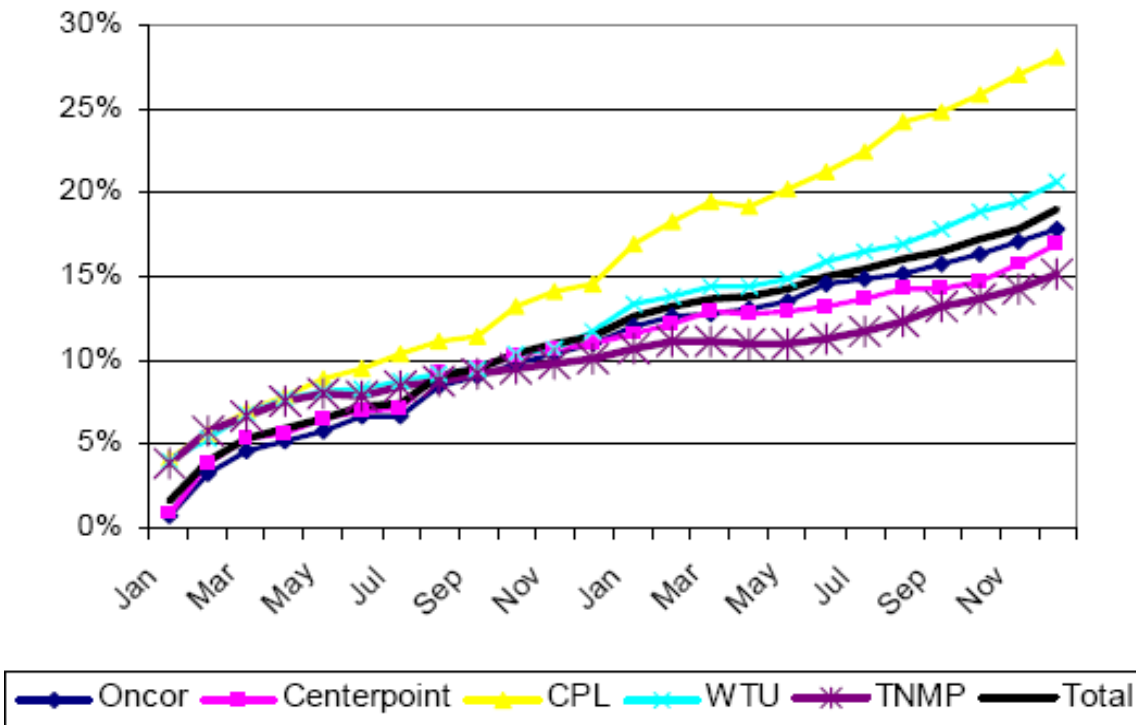




**Figure VII.3.** Residential customers with competitive REP.  
 Source: Public Utility Commission of Texas, March 2004 Report Card on Retail Competition.

(primarily smaller commercial and industrial customers, most of which are eligible for the price-to-beat) were receiving power from competitive REPs by December 2003. CPL had the highest percentage of these customer, while about 19 percent of all the secondary voltage customers were with a competitive REP by December 2003. Figure VII.5 shows that over 40 percent of the secondary voltage load (MWh) were with competitive REPs. CPL, again with the highest percentage, at over 60 percent the customer load.

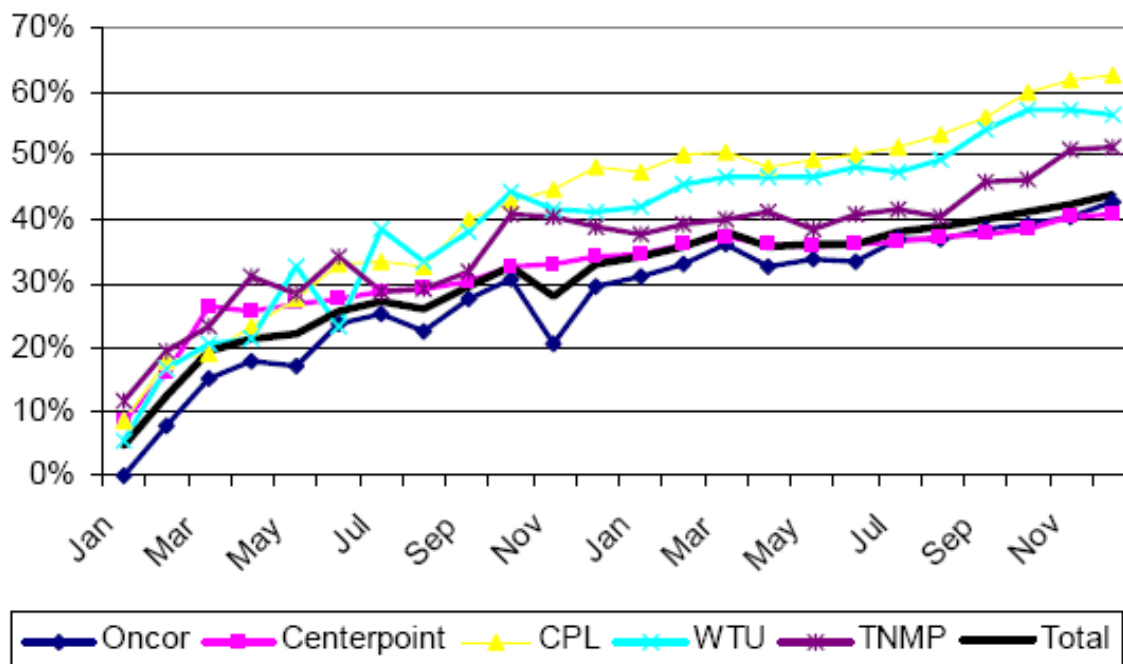
About 35 percent of commercial and industrial customers that receive service at primary or transmission voltage levels (larger commercial and industrial customers, many of which are not-eligible for the price-to-beat) were receiving service from a non-affiliated REP in December 2003 (Figure VII.6). (The Commission does not report a break down by TDU area because of concern for confidentiality of market share information for these customers by



**Figure VII.4.** Secondary voltage customers with competitive REP.  
 Source: Public Utility Commission of Texas, March 2004 Report Card on Retail Competition.

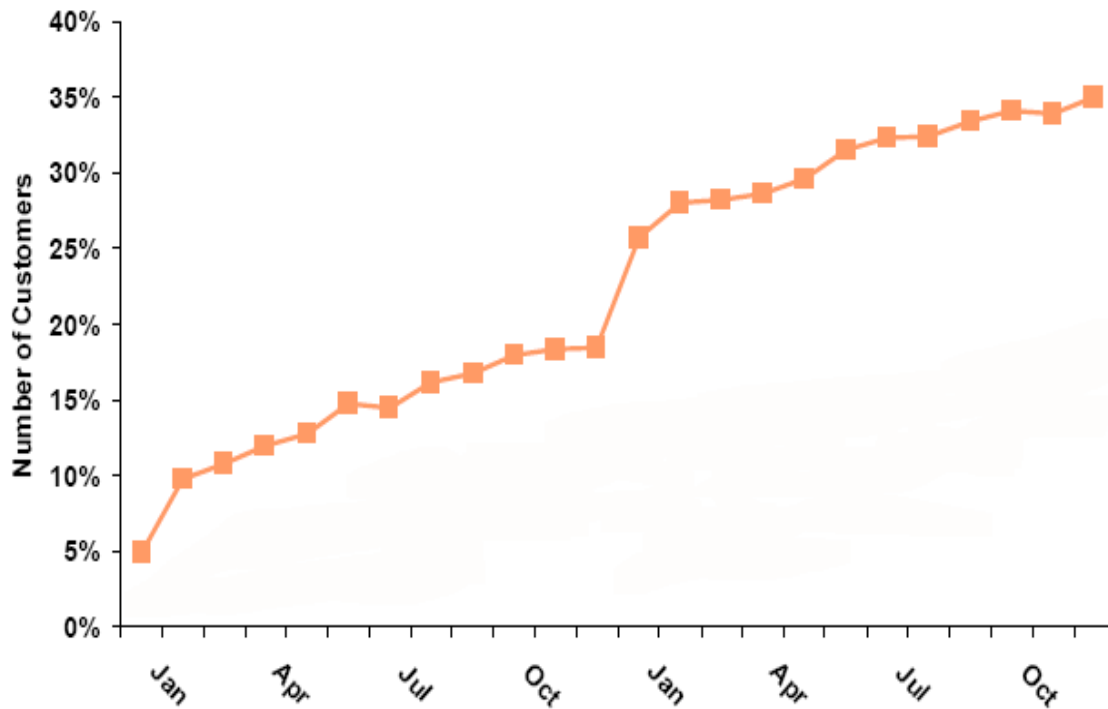
the affiliated REPs. They note that the trends are similar across TDU areas with respect to the number of customers that are being served by non-affiliated REPs.)

Customers without a price-to-beat available from the affiliated REP, are essentially in the market and were encouraged to choose to purchase power from the affiliated REP or a competitive REP. As seen nationally, because these customers use large amounts of power and have a strong incentive to consider alternatives, they are usually the most active shopping group and are usually the more sought after customers by retail suppliers. In addition, the Texas Commission required affiliated REPs to give the non-price-to-beat customers advance notice of the rate they would be charged on January 1, 2002, if they did not negotiate other arrangements with the affiliated REP or



**Figure VII.5.** Secondary voltage megawatt-hours with competitive REP.  
 Source: Public Utility Commission of Texas, March 2004 Report Card on Retail Competition.

switch to a competitive REP. The Commission reports that the default offers of the affiliated REP were generally either a very high fixed price offer or a pass-through of market prices, both of which may be considered risky options for most retail customers. This likely provided added incentive for these customers to shop for the best available price, since the default offers may lead to rates higher than those in effect before retail access began. No percentage numbers were released by the Commission for these customers since early 2003, however, as of December 2002, approximately eight percent of the non-price-to-beat customers remained on this default pricing offer, or approximately 92 percent of these customers have negotiated a competitive contract with either the affiliated REP or a non-affiliated REP.



**Figure VII.6.** Primary or transmission voltage customers served by non-affiliated REPs.

Source: Public Utility Commission of Texas, “State of the State –A Brief Review of Electric Competition,” April 27, 2004.

Stranded Cost True-Up

Utilities are required to finalize their stranded cost determination in 2004 through a market valuation of assets. The Commission is concerned that because of the current level of uncertainty and the lack of investor interest in wholesale generation companies, the market-based valuations of generation facilities or companies that own them may result in significant stranded costs for several companies. High stranded costs would, in turn, likely result in higher delivery charges from the TDUs. In Texas (as in many other states), the

Commission noted that stranded costs are predominately related to nuclear generation assets' high capital costs.

The initial estimates of stranded costs were made during the cost separation cases filed by the utilities in April 2000. In large part due to high estimates of natural gas prices, the Commission found initial estimates of stranded costs to be negative, that is, estimates of the market value of the generation resources exceeded the net book value of the assets. As a result, the Commission did not establish interim CTCs and instead ordered the utilities to begin returning stranded cost mitigation to customers as a credit to the non-bypassable charges (the "excess mitigation credit," or EMC).

In December 2001, the Commission adopted a rule to establish the procedures by which formerly integrated utilities will conduct their true-up proceedings in 2004. The primary purpose of the true-up proceedings is to reach a final determination of the utilities' stranded costs as the new rule establishes the process for quantifying the stranded costs of the utilities, and the reconciliation of that amount with prior estimates is used to set rates. Several investor-owned utilities have appealed the true-up rule.

TXU and Entergy have both agreed to forego further stranded cost recovery, and will not be conducting true-up proceedings as a result of these settlements. Reliant/Centerpoint, TNMP, and CPL/AEP are required, barring additional settlements, to finalize their stranded costs. In early 2004, the Commission reported<sup>7</sup> that Reliant/CenterPoint had stranded costs of \$2.4 billion, requested true-up of \$1.4 billion and other adjustments of \$0.6 billion, for a total of \$4.4 billion. TNMP had stranded cost of \$307 million, requested true-up of \$107 million, less other adjustments of \$57 million, for a total \$357 million. Estimate for CPL/AEP were \$1 billion in stranded costs and true-up of \$0.5 billion.

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<sup>7</sup>Public Utility Commission of Texas, presentation before Senate Business and Commerce Committee, "State of the State –A Brief Review of Electric Competition," April 27, 2004.

The rule amendments included a “transmission cost recovery factor,” or TCRF, that permits a utility to receive expedited cost recovery of additional transmission investments, and include those costs in the non-bypassable rates that are charged to retail customers. The TCRF is to only recover the capital costs associated with new investments in transmission facilities, and is subject to reconciliation in the transmission utility’s next transmission rate case. The Commission believes that the TCRF mechanism will encourage the timely construction of new transmission facilities needed to facilitate competition by reducing the risk to the transmission utility of making such investments. (This is similar to a FERC proposal issued in January of 2003.)

## **SECTION VIII West**

### **Wholesale Markets in the West**

Currently, there is one functioning ISO in the west, the California ISO. The California ISO began operation on March 31, 1998 and is a not-for-profit public benefit corporation that operates California's wholesale power grid. The ISO covers most of the state, with members that include the three major distribution companies in the state, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company. The ISO's principal function is to maintain reliability in its operation of the power grid that serves 30 million people in the state. The ISO has 25,526 circuit miles of transmission lines that it manages and supervises the maintenance on, but the transmission systems are owned and maintained by individual utilities. The ISO also acts as a transmission planner, identifying and approving enhancements transmission owners make to the grid to meet high reliability standards.

The ISO coordinates about 40,000 arrangements for electricity every hour between buyers and sellers, tracking prices and the settlement system, but does not buy or sell power itself. The ISO operates three markets to allocate transmission capacity, maintain operating reserves, and match supply with demand. However, these markets together make up less than ten percent of the total wholesale electricity market. The three markets the ISO operates are:<sup>1</sup>

(1) Ancillary Services Market – for adjusting the flow of electricity for unexpected events, such as a power plant failure or a sharp rise in demand for power. The capacity that is bought and sold can be dispatched within seconds, minutes or hours. The Ancillary Services Auction is conducted for day-ahead and hour-ahead of when the electricity is used for:

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<sup>1</sup>This information is from the California ISO, at <http://www.caiso.com>.

Regulation — generation that is already running (synchronized with the power grid) and that can be increased or decreased instantly to keep energy supply and energy use in balance;

Spinning Reserves — generation that is running, with additional capacity that can be dispatched within minutes;

Non-Spinning Reserves — generation that is not running, but can be brought up to speed within ten minutes; and

Replacement Reserves — generation that can begin contributing to the grid within an hour.

(2) Transmission Market – to allocate space on the transmission lines for the day-ahead and the hour ahead of when electricity is delivered. When there is transmission congestion, Scheduling Coordinators operating in congestion zones can participate in the congestion management market, curtailing their power deliveries or generating more.

(3) Real-Time Imbalance Market – for supplemental energy that can be quickly bought or sold every 10 minutes to accommodate energy use moments before it occurs. Scheduling Coordinators receive payment for extra generation they supply or are billed for extra energy they need to meet customer demand. Market Participants can submit incremental bids to supply more power, or decremental bids to reduce power output because of oversupply or congestion on transmission lines.

These markets are monitored by the ISO's Department of Market Analysis, that watch wholesale prices and look for any market power abuse. The ISO's Compliance Department ensures that market participants meet their obligations by monitoring responses to dispatch instructions and imposing penalties for non-compliance.

There are two other transmission organizations that are developing in the west. RTO West members filed a plan with FERC in October 2000 to form an RTO. FERC conditionally approved parts of the RTO West proposal as a "first step" in April 2001. The RTO would operate (but not own) transmission systems for participating transmission owners in California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming. This would be a non-profit independent operator. In March 2004, members of RTO West decided to change the name to "Grid West." In the southwest,



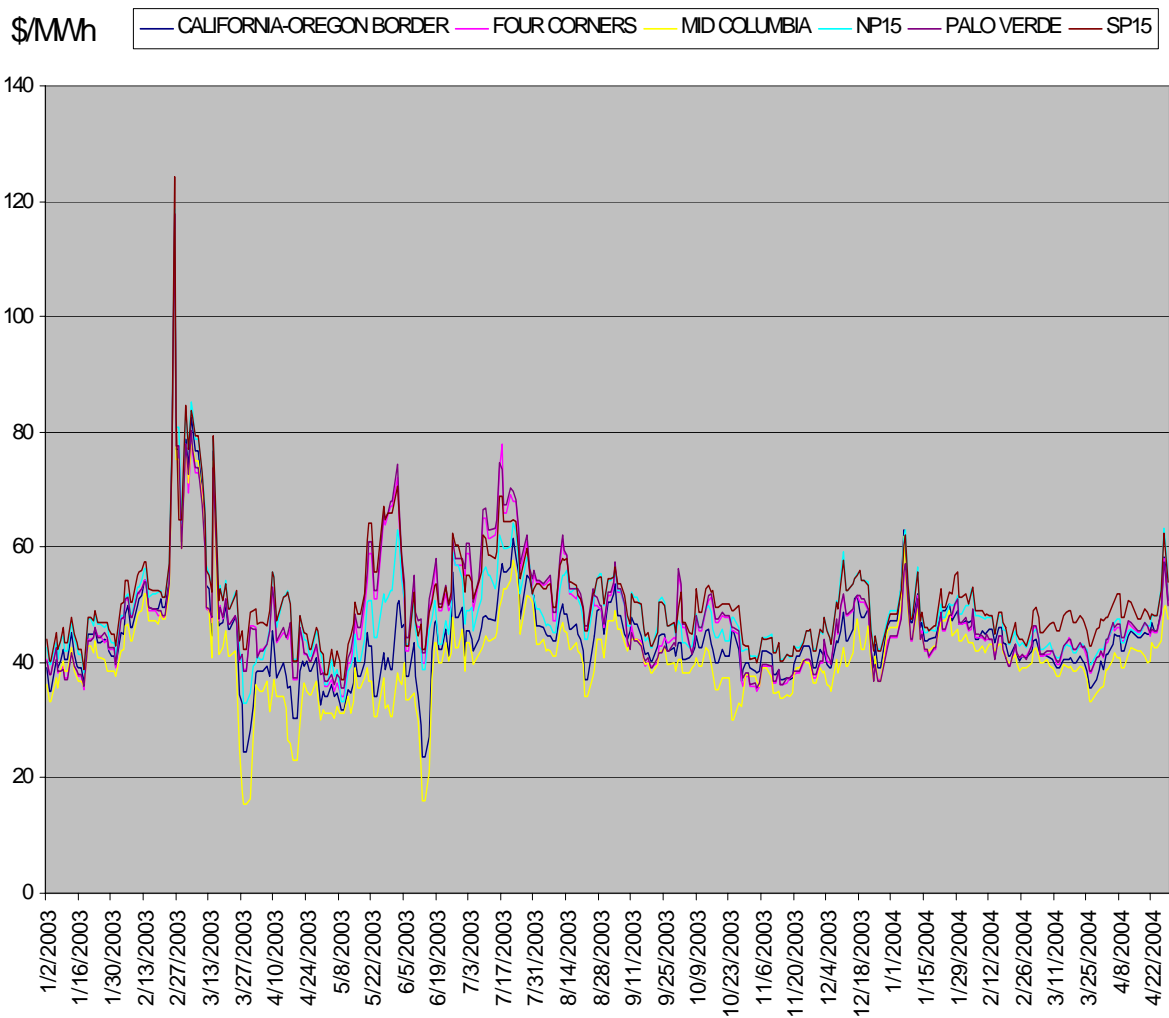
WestConnect (formerly DesertSTAR) members announced they would develop a for-profit RTO in October 2001 and received FERC's conditional approval. This area includes Arizona, Colorado, New Mexico, and parts of Texas and Wyoming. A grid-wide tariff for WestConnect may not be in place until 2009 and an operational RTO until 2011. The geographic areas of all three western transmission organizations are shown in Figure I.4 in Section I.

FERC had indicated at one time that they preferred a single western RTO. However, plans have been proceeding with the three transmission organizations as just described. All three of these transmission organizations in the west, California ISO, Grid West, and WestConnect, are working with the Seams Steering Group - Western Interconnection (SSG-WI), created in 2002, to discuss and deal with "seams issues" to coordinate the three organizations and perhaps create a "seamless" western market in the future.

Figure VIII.1 graphs *Megawatt Daily's* volume weighted-average (peak hour) price indices for six wholesale hubs in the western region.<sup>2</sup> Mid Columbia, in the northwest, is primarily hydro-based and generally the lowest cost. The other price indices move together in a relatively tight range given the wide geographic area they cover. As with other power markets, the natural gas price spike in early 2003 caused all the price indices to move higher nearly in unison.

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<sup>2</sup>Platts describes the hubs as follows: California-Oregon Border: deliveries at the Captain Jack and Malin substations in southern Oregon. Four Corners: deliveries at the Four Corners, Shiprock and San Juan substations in northwestern New Mexico. Mid Columbia: deliveries at ties to a number of dams on the Columbia River, namely Midway, Rocky Reach, Wells and Wampum/Vantage. Power at the John Day dam is priced separately and not part of this index. NP 15: deliveries north of Path 15 in California on selected ties between Los Banos and Gates. Palo Verde: deliveries at the Palo Verde switchyard in southeastern Arizona. SP 15: deliveries south of Path 15 in California on selected ties between Gates and Midway.



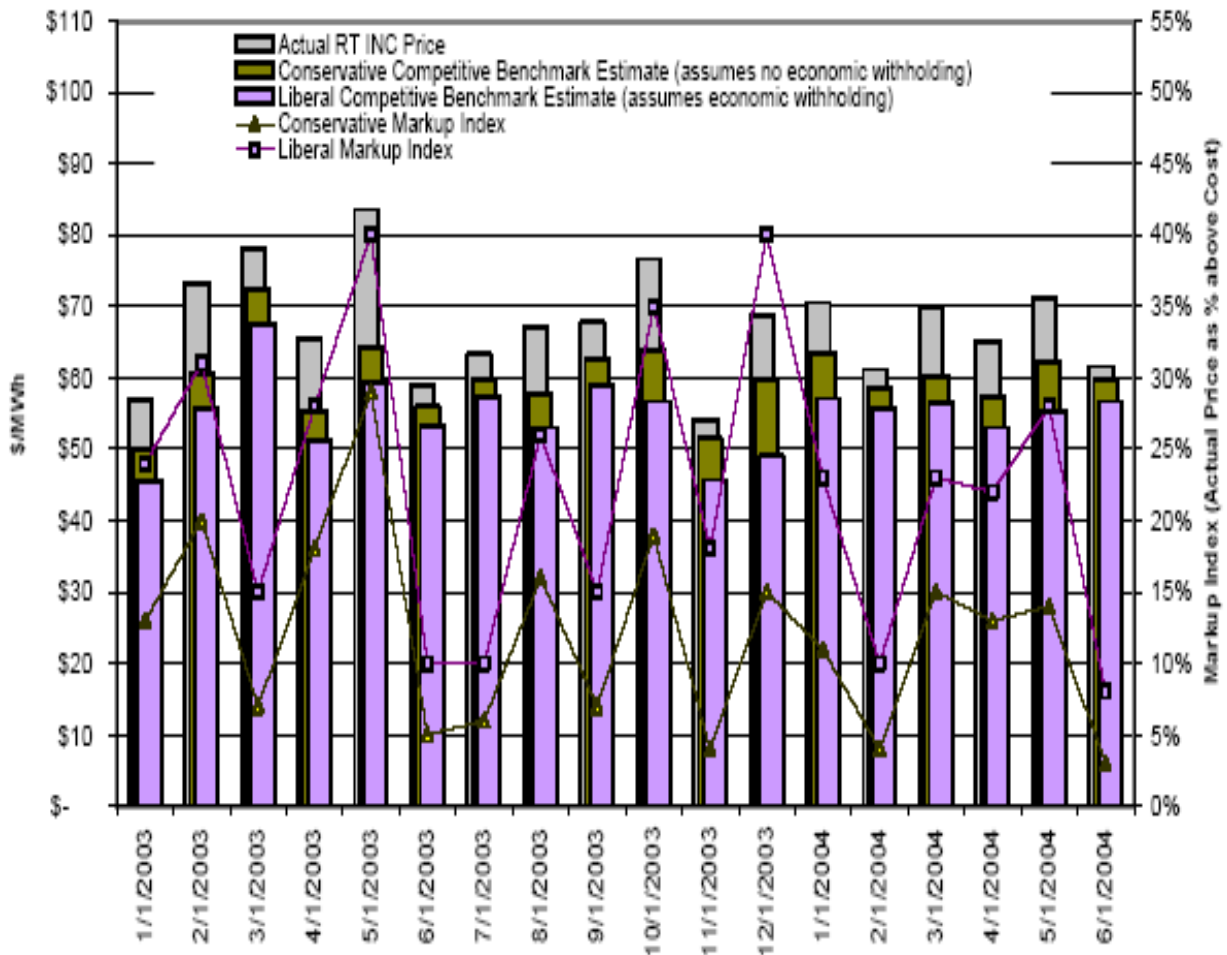
**Figure VIII.1.** Daily weighted-average wholesale power prices in the western region. Data Source: Platts, *Megawatt Daily*.

### Wholesale Market Performance

Previous Performance Reviews summarized several analyses of the California and western power crisis that occurred from late May 2000 through July 2001. These analyses have been conducted by the California ISO's internal market monitor, the Department of Market Analysis, the Market Surveillance Committee members, and others. Because of the power crisis, California's market is perhaps the most studied

and evaluated market in the country, for the crisis period. For more recent analyses, only the California ISO of the three transmission organizations in the West conducts ongoing analysis of its markets.

As an update of previous Performance Reviews, Figure VIII.2 is a graph created by the California ISO's Department of Market Analysis of the monthly average market clearing prices and their estimated markups for the real-time incremental energy market for January 2003 to June 2004. The actual real-time incremental energy price is generally higher, as might be expected since it is for short-term sales, than the wholesale index prices seen in Figure VIII.1. They calculate the markup using two



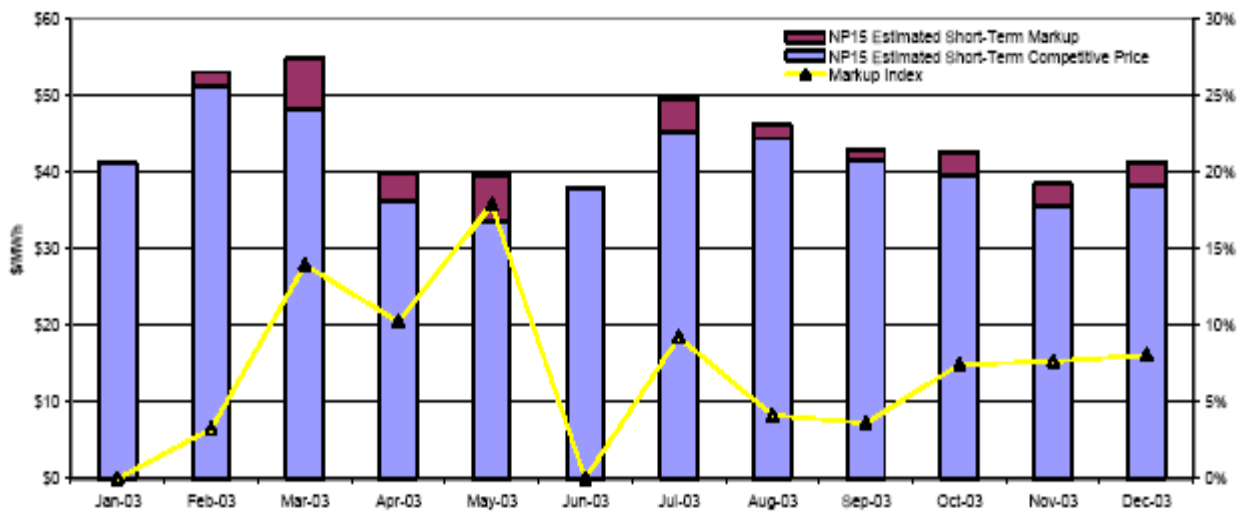
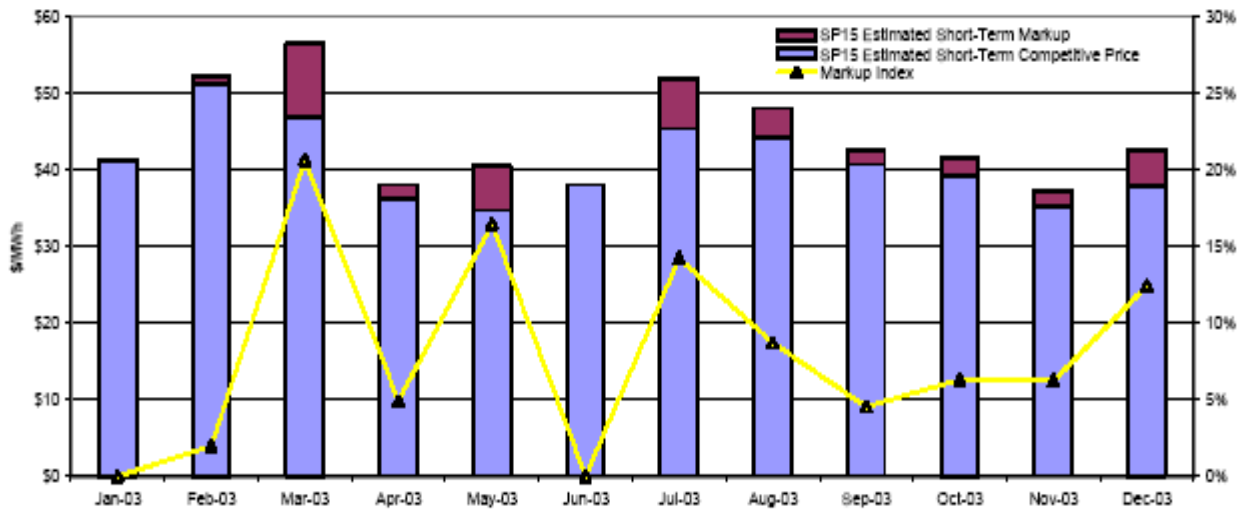
**Figure VIII.2.** Monthly average competitive market clearing prices and markups in real-time incremental energy market, January 2003 to June 2004. Source: Greg Cook, "Market Update," Market Surveillance Committee Meeting, California ISO Department of Market Analysis, July 16, 2004.

different methods to calculate the competitive benchmark estimate, which is an estimate of the price that would occur under competitive conditions for comparison with the actual price.<sup>3</sup> The markup is then calculated as the percent of the actual price that is above the benchmark estimated price. The “conservative” benchmark assumes no economic withholding, while the “liberal” benchmark assumes there is economic withholding. There is considerable variation between the two methods and from month-to-month. The “liberal” markup index reaches 40 percent in May and December 2003. The “conservative” markup index, except for May 2003, is at or below 20 percent. This market is a relatively small portion of the California wholesale market and the market clearing prices generally are higher than the wholesale prices, which may increase the markup.

Figure VIII.3 is also a graph created by the California ISO’s Department of Market Analysis, of 2003 SP 15 and NP 15 estimated short-term price-to-cost markups. For both price indices, the markup indices are at or below 20 percent and are often below ten percent. Much lower than the markups calculated for the crisis period, which were sometimes above 50 percent and were for the statewide Power Exchange.

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<sup>3</sup>This is an estimate of the marginal cost for the markup calculation, that is similar to the Lerner Index discussed in Section I. That is,  $(\text{Price} - \text{Marginal Cost})/\text{Price}$ , which measures the markup of price over marginal cost (as a percentage of price).



**Figure VIII.3.** 2003 estimated short-term price-to-cost markups indices for SP15 and NP15.

Source: Greg Cook, "2003 Annual Report on Market Issues and Performance," Board of Governors Meeting, California ISO, April 22, 2004.

## **Retail Markets**

While there are some large retail customers in the market in California, Montana, and Oregon, in general, western state retail markets have not fully recovered from the California and western power crisis and remains relatively inactive.

### **Arizona**

In 1996, the Arizona Corporation Commission (ACC) adopted rules that required the start of electric competition in 1999 for the utilities that the ACC regulates. Those rules were modified in 1998, 1999, and 2000. Also, in August 2002, the ACC eliminated the requirement for utilities to divest generation assets and the requirement that all power needed for standard offer service be purchased in the competitive market. The Electric Competition Act, (HB 2663), signed in 1998, allowed phased-in competition in Arizona for the utilities not regulated by the ACC. Since January 1, 2001 all areas of the state have been open to retail competition. There was an initial round of offers by alternative suppliers in 1999 and 2000, but has been no retail activity since then and now there are no customers served by alternative suppliers. In 2004, the ACC and interested parties are developing a process for standard offer competitive bidding.

### **California**

California suspended the retail access program it already had implemented in September 2001, more than one year after the beginning of the California and western power crisis. Current law prevents customers from leaving their utility until 2013, when the long-term power contracts entered into by the state expire. Under discussion in the legislature is a bill that would create "core" and "non-core" customer groups. Core customers, residential and small business customers, would remain with the local utility. Non-core customers, large business customers, would be allowed to switch to a competitive service provider, after paying an exit fee. An earlier bill under discussion in the legislature would have essentially repealed the state's original restructuring law.

Some customers (mostly large industrial customers) that were receiving power from alternative suppliers before the suspension of retail access remain in the market.

## Montana

Montana has also been dealing with the severe aftermath of the western power crisis. They implemented retail access for large industrial customers in July 1998, but residential access originally scheduled to begin by July 2002 has been postponed to July 1, 2027 (there have been two previous extensions of the transition period to retail access for smaller customers). The extension of the transition period was in a law signed by the Governor in May 2003 and would also require smaller customers to continue to be served by their distribution company in central and western Montana, but mid-sized and larger customers are still allowed to choose an alternative supplier. After Montana passed its restructuring law in 1997, there was some retail market activity early on for larger customers after retail access began. However, these larger customers paid much higher prices as a result of the western power crisis of 2000 and 2001. Many of these customers remain in the market, at this time, 87 percent of the large customer load or 34.2 percent of the total customer load in the central and western part of the state (NorthWestern's service territory) was being served by competitive suppliers.<sup>4</sup>

Montana Power, which at the time the restructuring law was passed was the main utility in the state, sold all its energy assets. Most of its generation assets were purchased by PPL Corporation in December 1999. In January 2001 Montana Power sold its electric and gas distribution system to NorthWestern Corporation. Montana Power then became a telecom company, "Touch America," which is now in bankruptcy. As a result of the sale, the generation assets of Montana Power became wholesale facilities that are no longer price regulated and no longer under the jurisdiction of the Montana PSC. This divestiture was voluntary and was not required by the state's restructuring law.

NorthWestern has no power plants in Montana and must purchase power in the wholesale market for its customers. NorthWestern also filed for bankruptcy protection

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<sup>4</sup>Personal communication, NorthWestern Corporation, August 2004.

on September 14, 2003. This was driven by NorthWestern's non-utility affiliates, not the gas and electric distribution systems in Montana.

The Montana PSC adopted guidelines in March 2003 for default supply, resource planning and procurement, and portfolio management after a roundtable process. The planning and procurement goals include having adequate, stable, reliable, and reasonably priced electric service.

## Nevada

Nevada had originally planned to allow retail access for all customers but modified their restructuring law to limit access to only large customers. Nevada passed restructuring legislation AB 366 in July 1997. But, due to the California crisis, the restructuring statute was revoked in April 2001. This repeal was to halt retail access permanently and freeze utility rates until early 2002. But a law enacted in July 2001 partially restored retail access for large customers (1 MW and above) with the approval of the Commission. Customers must provide evidence of the impact from their leaving the system will have on other customers. The petition to exit their utility could be denied or an exit fee could be charged, if a significant cost is involved. Large customers have been granted permission to leave their utility in Nevada, but as of early 2004, none have actually done so due to the exit costs and transmission access.

## New Mexico

New Mexico passed restructuring legislation in April 1999 that would have allowed retail access for residential, small consumers, and public school customers beginning in 2001 and all other customers by January 2002. A five year delay was enacted in March 2001. But this was rescinded in April 2003 when the Governor signed a bill that repealed the 1999 restructuring law.



## Oregon

Oregon passed a restructuring law in 1999 that limited retail access to only larger non-residential customers. Retail access to these customers was set to begin by October 2001, however legislation delayed it until March 1, 2002. A small percent of the state's non-residential load (less than five percent) is served by competitive suppliers.

## Biography

**Kenneth Rose** has been working on energy and regulatory issues for twenty years. He has testified or presented at many legislative and public utility commission hearings, proceedings, conferences, and workshops on electric industry issues and has testified before several congressional committees. Dr. Rose 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 market monitoring, and other industry restructuring issues. He is a frequent presenter at conferences, workshops, and other instructional venues and is quoted often in national newspapers and trade publications. Dr. Rose is a Senior Fellow at the Institute of Public Utilities at Michigan State University and lectures for the School of Public Policy and Management at The Ohio State University. Dr. Rose was a Senior Institute Economist at The National Regulatory Research Institute (at OSU) from 1989 until October 2002. Prior to NRRI, Dr. Rose worked on many energy related issues at Argonne National Laboratory from 1984 to 1989. Dr. Rose received his B.S. (1981), M.A. (1983), and Ph.D. (1988) in Economics from the University of Illinois at Chicago.