

**MANAGING DEFAULT SERVICE
TO PROVIDE CONSUMER BENEFITS
IN RESTRUCTURED STATES:
AVOIDING SHORT-TERM PRICE VOLATILITY**

**By
Barbara R. Alexander
Consumer Affairs Consultant**

**Prepared for
The National Energy Affordability and Accessibility Project
National Center for Appropriate Technology
June 2003**

Acknowledgements

This document was prepared for the National Center for Appropriate Technology (NCAT) as part of its National Energy Affordability and Accessibility Project. The Project researches the impacts of electric and natural gas retail market competition (also called energy industry restructuring) on residential consumers, particularly low- and moderate-income households. Funding was provided by the U.S. Department of Human Services, Administration for Children and Families, Office of Planning, Research and Evaluation (Award Number 90XPOO30/01).

The content of this publication does not necessarily reflect the views or policies of the U.S. Department of Health and Human Services, Administration for Children and Families.

About the Author

Barbara R. Alexander is the former director of the Consumer Assistance Division at the Maine Public Utilities Commission, where she served from 1986-1996. She opened her own consulting practice in March 1996. Her special area of expertise has been the exploration of and recommendations for consumer protection, universal service programs, service quality, and consumer education policies to accompany the move to electric, natural gas, and telephone competition. She has authored "A Blueprint for Consumer Protection Issues in Retail Electric Competition," as well as a series titled: "Default Service: Can Residential and Low-Income Customers Be Protected When the Experiment Goes Awry?" for the U.S. Department of Energy. A previous paper, "The Transition to Retail Competition in Energy Markets: How Have Residential Consumers Fared?" written by Ms. Alexander for NCAT and released in September 2002, documented the impacts of passing through short-term wholesale energy market rates to consumers in Massachusetts, Ohio, Texas, Georgia and New York. Her clients have included national consumer organizations, state public utility commissions, and state public advocates.

EXECUTIVE SUMMARY

The purpose of this paper is to examine recent developments with respect to the design and pricing of Default Service in states that have adopted retail electric competition and to identify the key attributes of a model Default Service policy.ⁱ Six states are examined in detail: Maryland, Montana, Connecticut, New Jersey, Massachusetts, and Pennsylvania. In this paper, the term “Default Service” is used generically to refer to the electric service provided to customers who do not choose a competitive electric supplier, or who are not able to obtain service from a competitive supplier. The importance of the pricing and design of this service cannot be overstated because the vast majority of residential and small commercial customers (over 95 percent in most states that have adopted retail electric competition) do and will continue to obtain vital electric service as Default Service customers.

With the exception of the Georgia natural gas competition programⁱⁱ, every state that has adopted retail electric or natural gas competition has provided for a regulated Default Service, at least for a significant transition period. In addition, most states provided that this service would operate as a benchmark against which competitive energy suppliers would offer services to customers, typically approving a rate decrease or rate freeze that would be in effect during a transition period. The nature, pricing, and availability of this service after the state-mandated transition period was often left for future decision by states at the onset of retail competition.

The move to retail competition for the sale of electricity at the state level has halted,ⁱⁱⁱ and several states have reversed the course back to fully regulated electric service^{iv}. Other states are attempting to continue down the path of competitive electricity markets, but must do so in the context of almost no actual competitive offerings available to residential customers. Even where those offers have been made, the vast majority of residential and commercial customers have remained with the local utility or “default” provider. It is widely now assumed that any further progress toward competitive electricity markets will depend on the development of wholesale rather than retail competition, but the regional entities and national consensus about the manner and method of creating wholesale markets is far from clear.

As a result of these developments, most customers, and virtually all residential and small commercial customers, must be provided electricity by a “default” or “standard offer” provider. Where states have adopted restructuring and the protected rate caps or rate freezes are nearing an end, the identity and method of pricing this service is the subject of intense debate.

The state decisions about Default Service that have been made to date in 2003 indicate a cause for serious concern and a likelihood that current trends, if not reversed, will carry significant risks of harm to consumers, particularly residential consumers. Most state regulators in the Northeast and Mid-Atlantic regions remain strong supporters of the retail competition model, but have confused the support for this market model with the notion that Default Service should be priced based entirely on short-term wholesale market prices. This report describes recent developments in New Jersey, Maryland, and Massachusetts that confirm this worrisome trend, although legislation recently adopted in Connecticut may provide a better approach.

On the other hand, states in the Western U.S., perhaps in part due to their proximity to and influence by the disastrous market implosion and price increases in 2000 and 2001 in California, are forging a more long-term pricing policy that clearly contemplates a proactively managed portfolio of products and resources to govern the price of Default Service. Montana is the clearest example of this trend.

There is a pressing need for a new regulatory vision to guide the overall attributes and characteristics of this vital service, the most important of which is to make sure that Standard Electric Service is **managed** and not based solely upon volatile short-term wholesale markets.

Default service should be proactively managed to provide benefits to consumers. If Default Service is not managed by policymakers and regulators to assure reasonably stable and affordable electric service for consumers, particularly residential and small commercial consumers, the alternative is likely to be a service that relies on the pass-through of short-term wholesale market rates obtained by a competitive bids.

The reliance on short-term wholesale market prices to provide vital electric service to most consumers is a dangerous and risky business. If regulators and policy makers continue to follow this path, the risks to consumers will be considerable because of the short-term nature of the planning and acquisition of generation resources that follows from this approach, as well as the risks associated with obtaining 100 percent of the customer load in a single point of time that may reflect short-term price spikes or other fuel emergencies. It is unclear that markets alone will support the needed construction of new sources of power when they are needed. Certainly the implosion of many of the early participants in the new wholesale markets and the recent difficulties in raising capital for any power plant construction raises serious doubt as to whether investors have confidence in these markets. Furthermore, short-term markets do not develop cost-effective energy efficiency and or renewable energy resources. The resources that are the cleanest and lowest cost over their full life cycle get short shrift when standard offer service is purchased in short-term markets. (The Public Goods Charges as implemented in most states do not come close to capturing the full economic potential of energy efficiency.)

The key attributes of a **managed** Standard Electric Service are as follows:

- Assure stable, reliable, and affordable rates;
- Rely on a longer term, diverse portfolio of electricity products to assure balance and reduce risks of short-term volatility in prices or reliance on a resource mix subject to external events;
- Lower environmental impacts of electricity generation;
- Empower consumers with choices in the use and source of their electricity;
- Strengthen the development of public benefit programs to assure affordable service for low-income customers, as well as renewable and energy efficiency programs, funded by all ratepayers;
- Enhance system reliability and security; and
- Contribute to the development of a healthy wholesale electricity market.

The management of Standard Electric Service will vary among the states, but regulators should recognize that the provision of Standard Electric or Default Service will require pro-active planning and management, centering on risk assessment for both short-term and long-term acquisitions. Whether the portfolio is assembled by a default energy supplier or a state commission, it can rely on market mechanisms, such as competitive bidding, to take advantage of competitive supplier offerings in the wholesale market. In addition, the portfolio should reflect explicit support for energy efficiency and renewable energy resources. Finally, consumers should be empowered to respond to both short and long-term price signals in their use of electricity by offering rate options and voluntary programs to shift usage, rely on renewable energy resources, or use electricity more efficiently.

MARYLAND

Background. Maryland’s restructuring statute required electric utilities to provide electric supply service to customers who were not serviced by an alternative supplier until June 30, 2003, but this obligation was extended until June 30, 2004 in some of the restructuring settlements voluntarily entered into by the utilities and other parties prior to the onset of retail competition. This obligation was extended even longer for two electric utilities—until June 2006 for Baltimore Gas & Electric and until June 2008 for Allegheny Power. Under the Maryland Electric Customer Choice and Competition Act of 1999^v, this service is known as Standard Offer Service.

Section 7-510(c)(3)(ii) requires the Commission to extend the SOS obligation to residential and small commercial customers “if the Commission finds that the electric supply market is not competitive or that no acceptable proposal has been received to supply electricity to those customers. ...” However, this determination must be made annually. If the obligation to provide SOS is extended, it must be provided at a “market price....” Section 7-510(c)(4) of the Act calls for the Commission to establish procedures for the competitive selection of electricity suppliers for the provision of SOS, but this process can be delayed.

Legislative and Regulatory Developments. In response to the need for interpretation of these statutory directives, the Maryland Public Service Commission decided the following key points in 2002^{vi}:

- The Commission can decide whether the electricity supply market is competitive without conducting a competitive bidding process. The Commission determined that the statute allows two alternative paths to call for the extension of the SOS obligation: either the Commission finds that the market is not competitive or it conducts competitive bidding with a failed result.
- The Commission can delay the implementation of a SOS selection process for reasons other than and independent from the alternatives described in Section 7-510(c)3. In other words, the ability to delay the use of a competitive bidding process to select the SOS provider can be done independently of a decision concerning the extension of the utilities’ obligation to provide SOS.
- The competitive bidding process can be used to obtain electric generation supply at either a wholesale or retail basis. In other words, while the statute is not clear, the Commission determined that it could supervise a process by which the utilities obtain generation supply in the wholesale market, the price of which is passed through to their retail customers, or supervise a process by which suppliers bid to service SOS customers at retail.
- When asked to provide guidance on whether the electric utilities (or any other party) should provide a “provider of last resort” service when a competitive supplier terminates their relationship with a residential or small commercial customer or such customers refuse to accept service from the competitive supplier, the Commission declined to do so. In other words, it is not clear whether there is a back-up service to competitive provision of SOS after July 1, 2004.

On November 15, 2002, a Settlement Agreement was filed with the Commission to resolve the provision of SOS and default service to customers by means of a competitive selection of wholesale supply service for specific service periods. The Settlement Agreement was filed by a diverse group of parties, including all the electric utilities, representatives of residential customers, industrial customers, and the Office of People’s Counsel. The only party to oppose the Settlement was Washington Gas Energy Services. After a lengthy period of briefs and argument, the Commission approved the Settlement on April 29, 2003.^{vii}

In approving the Settlement, the Commission found that retail competition had not developed as intended and noted that as of March 28, 2003, only 3.9 percent of all customers (3.7 percent residential and 5.2 percent non-residential) were taking service from a competitive supplier, representing 16 percent of the peak load obligation. As a result, the Commission determined that SOS must be extended pursuant to the option allowed under the Act.

Under the terms of the Settlement, there will be four types of SOS offered: one residential SOS and three types of non-residential SOS. SOS will be provided to residential customers by the electric utilities for a 4-year period beyond the SOS obligation at the price caps set forth in the restructuring settlements^{viii} and pursuant to rates set according to the results of a wholesale power bidding process^{ix}. The utilities must attempt to obtain 1-, 2-, and 3-year contracts, with 50 percent of the load to be served obtained through a 1-year contract. The resulting retail price for generation supply must be charged as fixed rates for each customer class. In addition to the generation supply contract rates, utilities are allowed to add an “Administrative Charge” to the wholesale price. Included in the Administrative Charge is an “Administrative Adjustment.”

While the Commission must approve the results of any bidding program, the Settlement sets out four components of the future price of generation supply:

- A seasonally-differentiated and, where applicable to the existing rate class, time-of-use differentiated load weighted average of the prices obtained through the competitive bid
- Transmission costs directly related to the SOS load obligation incurred by the utilities
- Applicable Taxes and
- A specified Administrative Charge intended to recover the utilities’ prudently incurred and verifiable incremental costs and reasonable return on those costs associated with the provision of SOS. It is set at 4 mills per kWh in the Settlement and it is composed of several different factors:
 - 1.5 mills per kWh for a return to utility shareholders, including cash working capital revenue requirement
 - .5 mills per kWh for the incremental costs associated with the obligation to arrange for and provide SOS (excluding residential SOS uncollectibles)
 - The settlement sets a proxy of 2 mills for the calculation of that portion of the SOS price that reflects the uncollectible expense for this service. Since there is an uncollectibles factor already reflected in SOS rates for BGE (but not other utilities), the Settlement calls for a reduction for in the remaining 2 mill/kWh portion of the Administrative Charge that is specified for each utility (1.1 mills for Baltimore Gas & Electric, 0.0 mills for Pepco and Conectiv), subject to revision in future base rate cases and
 - Administrative Adjustment, basically the difference between the 4 mills/kWh and the other specified factors above. For BGE, the Administrative Adjustment will be set of .9 mill/kWh, equal to the 4 mills less 1.5 mills for return, less .5 mills for incremental cost, and less 1.1 mills for SOS-related uncollectibles. The other utilities will reflect the full 2 mill/kWh portion as the Administrative Adjustment. This Adjustment will prevent the double recovery of charges that are already collected from customers in the distribution portion of the bill.

The revenues from the Administrative Adjustment will be credited back to residential distribution service customers in a per kWh credit. This Adjustment increases the apparent price of providing the retail service against which competitive suppliers compete and returns to residential ratepayers all revenues associated with this Adjustment. In fact, the Settlement calls for a reduction in this Adjustment to the Administrative Charge if competition more fully develops during the term of the Settlement.

Finally, the Settlement contains a provision that identifies the point at which customer switching to competitive suppliers may adversely impact the revenues of the supplier who has won the bid to provide the generation portion of the bill. Unless there is a 25 percent shift in customer load, there will be no fees or additional charges associated with switching, and the supplier providing SOS will bear the risk of reduced sales volume due to customer switching to other suppliers. Since only 3 percent of residential customers have ever experienced switching in Maryland, attaining this volume level to trigger switching fees or exit fees is unlikely in the near term.

Comments. Analyzed from the perspective of a precedent in the establishment of Default Service at the end of the statutory transition period, there are several aspects of the Settlement that should be considered by other states who may seek to follow this approach:

- First, the terms of any long-term obligation to provide SOS in Maryland is constrained by the current statute, which does not contemplate that the Commission could “anoint” the distribution utility with the obligation to procure this service for a longer period than one year at a time. It may be that the statute should be amended to reflect the realities of the current retail market for residential customers. Even so, the extension of this obligation for a four-year period beyond that already reflected in either the statute or the restructuring settlements is a welcome development, particularly since BG&E, the largest utility, has incurred this obligation until 2010 under the terms of the settlement.
- However, the relatively short-term nature of the generation supply contract period required by the Settlement is likely to delay any planning and capacity to manage a portfolio of products to obtain long-term price stability for residential and small commercial customers. The Settlement’s requirement that 50 percent of the load be obtained in the form of a one-year contract is particularly troublesome in this regard. On the other hand, the PJM Interconnection has enjoyed more stable wholesale market prices than other emerging regional wholesale power markets, thus the risk of higher prices (compared to current rates) as a result of this provision is lower than might result in other regions. Nonetheless, the four-year fixed rate that is likely to emerge from this wholesale bidding process will reflect short-term price determinations and delay any effort to develop a diverse portfolio of products that are likely to provide long-term price stability for residential customers.
- Finally, the Administrative Charge associated with the Settlement is heavily weighted toward utility interests and will result in higher prices for generation supply service than the barebones price of that product alone, because the Maryland statute required that the price of SOS reflect all conceivable incremental costs associated with providing that service, including a rate of return. This was interpreted in Maryland to also require the identification of the uncollectible expenses associated with the SOS portion of the bill. This approach, if followed elsewhere, will require vigilance to ensure that these costs are not being paid twice by ratepayers – once through the base rates for distribution services (all of which included cost recovery for these same cost categories in the pre-restructuring world) and again as the Adder for the generation supply portion of the bill.

MONTANA

Background. Montana was one of the first states to adopt electric restructuring, enacting SB 390 in 1997 (Electric Utility Industry Restructuring and Customer Choice Act). Customer choice was granted to large customers in 1998 and all customers were to be transitioned to customer choice over a four-year period. The largest incumbent investor-owned electric utility, Montana Power Co., was designated the Default Supplier for all non-shopping customers in 2000. Montana Power Co. sold its generation assets (mostly low cost hydropower facilities) to PPL, but subject to a contractual obligation by PPL to provide the necessary default supply energy to MPC's customers until July 2002. MPC then sold the distribution utility to NorthWestern Energy, approved by the Commission in early 2001. The dysfunctional Western wholesale energy market in 2000-2001 was not only unexpected, but it threw into turmoil the development of the competitive generation supply market and raised significant fears about the ability of any supplier to provide reasonably priced electric service to residential and small commercial customers.

Montana has debated the policies that should apply to the future of electric restructuring, a debate that has taken on even more significance with the defeat of a citizen's referendum in the fall of 2002 that sought to buy back the hydropower facilities sold to PPL. Both regulatory and legislative initiatives are under development to govern the acquisition of default supply in the future in light of the collapse of customer choice and the lack of competitive electric suppliers offering retail services in Montana.

Legislative and Regulatory Developments. In July 2002 the PSC initiated a number of forums to collaboratively develop default supply procurement guidelines and other restructuring-related issues and in November published proposed default supply procurement rules. At the same time, the PSC undertook a leadership role in the development of legislation that has been adopted in the 2003 Montana Legislative session.

The PSC adopted Rules Pertaining to Default Electricity Supply Procurement Guidelines on March 31, 2003^x. These rules set forth the process and policies that must be followed by "default supply utilities (DSU)." The new rules require the DSU to "plan and manage its resource portfolio in order to provide adequate, reliable and efficient annual and long-term default electricity supply services at the lowest total cost." [Rule V (38.5.8209)] A DSU may, but is not required, to offer a green or renewable energy product. The DSU is obligated to acquire its portfolio based on long-term needs and risk analysis. The term "long term" is not specified, but is defined as the longer of the term of any existing contract in the DSU's portfolio, the longest term of any contract under consideration for acquisition, or 10 years. The guidelines also make clear that demand-side management products and services must be considered as part of the portfolio. The rules do not require competitive bidding, but to the extent that the DSU does not rely on competitive solicitations, it must justify the alternative approach. The resource acquisition rules with respect to demand side management programs reflect the prior least cost planning rules that remain in effect in Montana for vertically integrated utilities: a prohibition on using a non-participant test, the need for targets to achieve a steady and sustainable use of demand side resources, a prohibition on "cream skimming" as the primary focus of demand side programs.

At the same time that the Commission was developing default supply procurement guidelines, the Legislature was considering a comprehensive bill to revise Montana's electric restructuring law. In its final form, HB 509^{xi} does not repeal retail competition, but it significantly restricts the volume of

customer load of some customer classes that can leave the default supplier. The bill inserts the following key policy decisions in Montana law:

- The incumbent electric distribution utility is required to serve as the default supplier pursuant to a portfolio of energy supply resources that provide “adequate and reliable default supply service at the lowest long-term total cost.” [Section 5, amending 69-8-102 Montana Code Annotated] The Commission is granted the authority to adopt procurement guidelines and approve any utility’s procurement plan and resulting default supply rates. Default supply service must reflect all electricity supply costs, defined to include capacity, energy, ancillary services, fuel, demand side management and efficiency costs, transmission, billing, planning and administrative costs, and other costs directly associated with purchase and provision of default supply service.
- Default supply service must be provided for a lengthy transition period that does not end until July 1, 2027, thus ensuring a long planning and acquisition horizon.
- The Commission may approve multiple default supply service options, but the DSU must offer its customers the option of purchasing a “product composed of or supporting power from certified environmentally preferred resources that include, but are not limited to, wind, solar, geothermal, and biomass, subject to review and approval by the Commission. [Section 12, amending Section 69-8-21- MCA]
- The bill contains restrictions on the amount of customer load for small, medium, and large customer classes that are eligible to participate in newly defined customer choice programs. The total average monthly billing demand for residential and small commercial customers who choose a competitive supplier cannot exceed 10,000 kW in each calendar year. With respect to large industrial customers, they will be granted a one-time option to arrange a permanent default supply contract with the utility by the end of 2003, but must otherwise arrange for service from the competitive market. Those customers who have already selected an alternative electric supplier may continue to be served by that supplier.
- The utility must arrange for a separate “emergency” default supply service to provide electric supply if a customer’s competitive default supplier suddenly exits the market. The price for this service will reflect short-term costs. Furthermore, the bill provides that the defaulting electric supplier must reimburse the distribution utility for the incremental costs for this service.
- Finally, the universal service programs and the social benefits charge that funds these programs is extended for two years, through 2005.

Comments. The Montana bill and Commission’s default supply service guidelines constitute the first example of a comprehensive policy that seeks to assure long-term and stable prices for default energy service in light of the failure of the retail competitive market to provide reasonably priced service to most customers, particularly residential customers. The collaborative approach reflected in these proposals reflects as well a growing consensus in Montana that the distribution utility must be charged with the necessary policy direction and the assurance that a well-designed and diverse portfolio of contracts and energy supply options must be proactively managed based on long-term price signals. While it did not repeal the restructuring experiment, Montana has now enacted policies that should become a model for other states that must take actions in light of the failure of the retail restructuring experiment.

CONNECTICUT

Background. Connecticut's restructuring law established a transition period that is due to end on January 1, 2004, unless that date is extended by the General Assembly. The restructuring law (PA 98-28) required incumbent utilities to provide a Standard Offer for four years, 2000-2003. The intent of the Standard Offer was to reduce customer rates by 10 percent compared to rates in effect on December 31, 1996. By the time customer choice was initiated in 2000, baseline rates had already been reduced by this amount for the two largest utilities, Connecticut Light and Power and United Illuminating. The integrity of the Standard Offer rates and the 10 percent rate reduction has been maintained even though there has been significant pressure exerted by suppliers and utilities to increase rates. The utilities are still recovering stranded costs and will do so until 2010, six years after the Standard Offer expires. In addition, the two investor-owned utilities sold their generation assets and no longer have access to cost-based energy supply, but must rely on the wholesale market.

As in most states, there has been little or no evidence of competitive offerings or customer interest in customer choice by residential and small commercial customers. According to Connecticut's Department of Public Utilities Electric Choice website, there are no licensed suppliers seeking residential customers as of January 23, 2003.^{xii} On the other hand, there appears to be little consensus that Connecticut should repeal retail competition and "re-regulate" electric rates. Rather, most proposals focus on structuring a default service that must replace the Standard Offer Service in 2004.

Legislative and Regulatory Developments. SB-733, An Act Concerning Revisions to the Electric Restructuring Legislation, was adopted by the General Assembly on May 27, 2003 and is expected to be signed by the Governor. This bill appoints the distribution utility as the default supplier. The current rate-capped Standard Offer is extended for three years, creating a new "transitional standard offer" that terminates on January 1, 2007, but it increases the rate that can be charged for that service, by eliminating the 10 percent rate reduction from 1996 rates that was in effect for the past four years and excluding "federally mandated congestion costs" from the cap on rates. This term refers to the FERC mandated congestion management charges reflected in wholesale market transmission rates for Connecticut that were formerly reflected in customer rates throughout New England, but that must now be paid by Connecticut customers due to the congested transmission system in the southwest portion of the state. In addition, the distribution utility may receive "compensation" for the provision of transitional standard offer service in an amount equal of .05 mills per kilowatt hour^{xiii}. An incentive payment is also authorized for those utilities that successfully mitigating the price of the contracts for the provision of this service below the regional average. As a result, consumer rates are expected to increase at least 10 percent and probably more during this next "transition period."

Starting in 2007, customers with a maximum demand of less than 500 kW^{xiv} who do not choose a supplier will be provided a "Standard Service" pursuant to the DPUC-approved plan. The plan must require that a "portfolio of service contracts be procured in an overlapping pattern of fixed periods at such times and in such manner and duration as the department determines to be most likely to produce just, reasonable and reasonably stable retail rates while reflecting underlying wholesale market prices over time." [Section 4 (c)] The portfolio must avoid "unusual, anomalous or excessive pricing." The contracts must be for terms of not less than six months unless a shorter term contract is likely to result in lower rates and ensure reliable service. The plan does not require that the contracts be obtained in a particular manner, but contemplates competitive bidding to be overseen by the DPUC.

The bill also contains extensive provisions designed to stimulate the development of renewable energy resources and demand management programs. The renewables energy portfolio requirement is made applicable to the Standard Offer, but the timetable for achieving the required minimum percentages that was adopted in the original restructuring law is extended. Furthermore, the DPUC can approve alternatives to the standard offer for renewable energy or demand response program options so that customers may be offered these as options to the Standard Offer.

The legislation does not mandate any administrative fee for the provision of Standard Service starting in 2007, but does clearly state that utilities may recover the “actual net costs of procuring and providing electric generation services pursuant to this subsection, provided such company mitigates the costs it incurs for the procurement of electric generation services for customers who are no longer receiving service pursuant to this subject.” [Section 4(c)] In addition, utilities can be compensated for “mitigating the prices of electric supply contracts” pursuant to an approved incentive plan for procurement of long-term contracts in an amount that will not exceed 2.5 mills per kwh.

Comments. Similar to Montana, the Connecticut legislation is attempting to establish default service policies for a longer time period. Beginning in 2007, the legislation establishes a statutory directive for a portfolio of long-term contracts with fixed rates that, while not specifically stated, is likely to result in more stable rates than any scheme that relies on short-term wholesale market rates. However, this is the first state in the Northeast to contemplate the adoption of a managed portfolio of contracts and products for Default Service. Even so, there are some aspects of this bill that are not “ideal” from a consumer prospective:

- The pass-through fees to utilities for administration fees are not, unlike the Maryland Settlement, backed out of current rates. Ratepayers may pay twice for these services. Furthermore, the assumption that utilities will incur costs associated with obtaining and managing default service contracts that significantly exceed costs that are currently incurred and reflected in rates for this purpose is undocumented.
- The fact that the legislation does not specifically define the time horizon for the overlapping contracts required for the post-2007 period is worrisome, as well as the lack of any planning horizon. It is not clear how “long” is “long term.” Nor is there any legislative direction concerning the frequency of rate changes that may occur.
- The requirements for passing through “federally mandated congestion costs” and the impacts of the renewable energy mandates for the default service portfolio are likely to increase rates, at least in the short run. There is no estimate of the impact of this requirement in the legislative debates or bill analysis.

NEW JERSEY

Background. New Jersey enacted restructuring in early 1999, with an effective date of August 1999 for retail competition. Similar to most state restructuring statutes, the Electric Discount and Energy Competition Act seeks to create competition in the wholesale and retail electricity and gas generation markets, allowing customers to shop for the cheapest generation source. To achieve these goals, EDECA provided the following:

- Utilities were enticed to either divest generation assets or transfer them to separate affiliates by an offer to allow increased use of the securitization tool for stranded cost recovery.
- Utilities were required to provide Basic Generation Service to all customers who did not choose a competitive energy supplier. This service is subject to the regulation of the Board of Public Utilities (BPU).
- EDECA mandated electric rate reductions of at least 5 percent upon implementation of the Act and at least 10 percent by the beginning of the fourth year of deregulation. The BPU was authorized to distribute these aggregate rate reductions to any portion of the utility bill. These rate reductions, which are imposed until August 2003, are based on the rate levels as of April 1997.
- EDECA guarantees utilities “the opportunity to recover above-market power generation and supply costs and other reasonably incurred costs associated with the restructuring of the electric industry in New Jersey.”^{xv} This means utilities can recover from ratepayers costs that were ‘stranded’ or unrecoverable as a result of deregulation, including interest, as well as unrecovered costs from providing BGS.
- While EDECA mandated 10 percent electric rate reductions, it also required ratepayers to reimburse utilities for deferred balances that might accumulate as a result of those discounts, that is, the difference between the mandated rate discounts and the actual cost of the energy that was acquired by the utilities to serve their customers. Consumers must begin to pay back these balances, plus interest, in August 2003, four years after the initial rate reduction. Therefore, ratepayers have been buying electricity on credit for four years, while EDECA-mandated statements on customers’ utility bills have been informing customers how much money they were saving because of rate caps. No other state in the nation has mandated inflexible rate caps for as long as four years and required ratepayers to pay back deferred balances, plus interest. Consequently, no other state has a deferred balance debt of the magnitude that New Jersey ratepayers now face.

The deferred balances have been estimated at approximately \$1 billion, although the level of deferred balances varies widely by individual utility. While ratepayers received modest rate reductions, the average customer of Conectiv (Atlantic City Electric) will now be responsible for approximately \$350 in deferred balance debt, the average Jersey Central Power & Light customer, \$685, and the average Rockland Electric customer, \$1,575. The largest utility, PSE&G, is not expected to have deferred balances.^{xvi}

Further complicating this picture, all the utilities have filed base rate cases before the BPU, and most seek distribution services or base rate increases in addition to the recovery of the deferred balances. The BPU currently has audits and formal rate proceedings underway for all four electric utilities, the outcome of which may include a long-term securitization of prudently incurred deferred balances.

Legislative and Regulatory Developments. The BPU has also made several key decisions in the methodology to be used to price Basic Generation Service because the mandated rate reductions and rate caps expired August 2003. The BPU has pioneered a unique wholesale auction to govern the price for BGS. In December 2001 the BPU determined that for year 4 of the transition period (i.e., August 2003-August 2004), electric utilities should continue to provide BGS, with the procurement of the generation supply to be achieved by means of an auction process^{xvii}. The auction was held in early 2002 pursuant to a multi-day electronic auction process supervised by a consultant to the Board. All the utilities were required to accept the result of this action and enter into full requirements contracts with the auction

winners pursuant to the Master Supply Agreement that had previously been negotiated by the parties and approved by the Board. The auction divided the customer load that must be served into 170 “tranches” (slices of customer load) to allow for multiple rounds of bidding by a wide range of licensed suppliers.

This auction was conducted as a “simultaneous declining block” auction. All the load of the electric utilities was bid out at the same time (approximately 18,000 MW), but the retail load of each EDC was considered a separate “product” for which a supplier could bid to serve all or part (“tranche” or fixed percentage share of a utility’s load). The auction is “descending” because the going prices are gradually reduced during the term of the auction. The auction ends when the total number of tranches bid equals the number of tranches that the Auction Manager (as the agent of the Board) has set as the auction volume. The bidders that hold the final bids when the auction closes are the winning bidders. The resulting bids are averaged for each utility’s tranches so that the resulting prices for generation supply service vary among the different utilities. As a result of the auction conducted in 2002 for Year 4, the closing prices were PSE&G-5.11; Jersey Central-4.87; Conectiv-5.12; and Rockland- 5.82.

After an extensive proceeding in 2002, the Board approved essentially the same approach for pricing BGS for the post-2003 period.^{xviii} The Board approved the same type of auction process, but required that a separate auction for Fixed Price service be conducted to obtain two-thirds of the utility load eligible for this service for 10- months^{xix} and one-third of the fixed price load for a 34-month period. The results of these two sub auctions will be blended in a single price for fixed price customers, notably residential and small commercial customers, for a full year (August 2003 until May 31, 2004). Other larger customers will obtain BGS service via an Hourly Energy Price auction and be required to take service through interval meters. The Board reserved for a later time its decision about the procurement process for a subsequent year (June 2004 through May 2005).

This auction was conducted in early 2003 and announced on February 5, 2003. According to the BPU, customer rates will increase on average 7.3 percent as a result of the auction. Individual utilities will experience different results: PSE&G-6.54 percent increase; Jersey Central-7.3 percent increase; Conectiv- 4.5 percent increase; Rockland- 4.3 percent decrease. These results do not include the base rate increases sought by the utilities (in the range of 8 to 12 percent) which will be decided this summer, along with the rate impact of deferred balances.

Comments. The New Jersey approach reflects the most sophisticated effort to attain “true” wholesale market prices based on competitive bidding. The fact that the entire utility customer load is available during one auction process is likely to draw the largest pool of suppliers and supply resources to this effort. On the other hand, the auction process itself reflects only short-term market trends, which in the PJM area is in a wholesale surplus situation. As a result, there is no long-term price stability, resource acquisition, or portfolio management occurring in New Jersey. New Jersey has truly put all its electricity eggs in the hands of the wholesale market for generation, and the fact that the vast majority of the customer load is bid out at the same time is a very risky business. While the PJM wholesale market has been relatively stable, at least compared to Western energy markets, the changes that are likely to occur as a result of the expansion of PJM to include New York and other large Midwestern utilities (such as Commonwealth Edison in Illinois) may result in unforeseen changes in electricity prices in the short term. Furthermore, the risk that the auction will be conducted during a time of market instability due to either a true shortage or market manipulation should also be considered.

MASSACHUSETTS

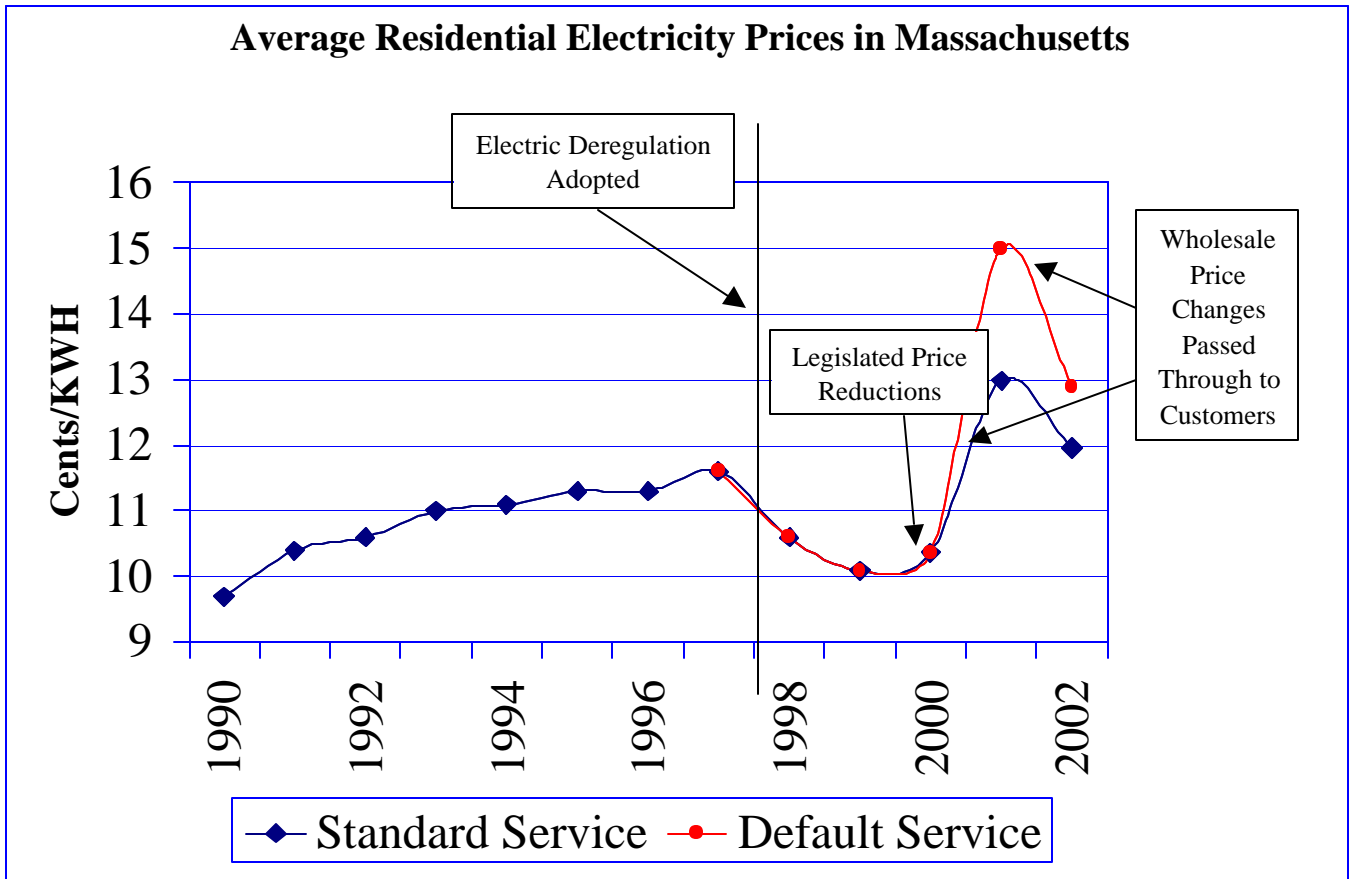
Background. The Massachusetts restructuring statute^{xx} creates two services for customers who do not select a competitive supplier or who are no longer served by a competitive supplier for any reason: “Standard Offer Service” (SOS) and “Default Service.”^{xxi} Standard Offer service is provided by existing utilities to all customers who choose not to choose and it reflects the statutory mandate for rate reductions (10 percent in year one and 15 percent beginning on September 1, 1999). Standard Offer service is only available for the transition period of seven years (until March 1, 2005). The Act provides a limited set of circumstances under which a customer may enter the competitive market and then return to this service, but basically new customers who move into a distribution utility’s service territory after March 1, 1998 (the onset of competition) or who seek to return to regulated rates after swimming in the competitive waters are not able to receive SOS. Customers who were being served by utilities in March 1998 may enter the competitive market and return once within 120 days, but otherwise customers who enter the competitive market are not otherwise eligible for Standard Offer Service. However, pursuant to statute, low-income customers (defined as those receiving the low-income rate discounts available at each utility) can return to Standard Offer service at any time.

Default Service is provided to any customer without a competitive energy supplier and who is otherwise not eligible for Standard Offer Service. The distribution utilities must offer both services under rates approved by the Department of Telecommunications and Energy (DTE). For the first several years of competition, the DTE ordered the utilities to provide Default Service at the same price as SOS. However, in mid-2000, the DTE decoupled Default Service rates from SOS rates. The Department ordered utilities to pass through a price that reflects short-term priced service obtained by bids in the wholesale market. The price must be fixed for six-month intervals or offered as a month-to-month variable rate for a six-month period. Residential customers who must obtain Default Service will be automatically placed on the fixed price rate, but will be offered the month-to-month variable price as an option. Commercial and industrial customers will be put on the variable price option and must seek the fixed rate upon request.

Prices for both Standard Offer Service and Default Service have increased since the onset of retail competition. Utilities sought rate increases based on the rising fuel prices in the wholesale market. In effect, the utilities sought a fuel clause adjustment to their rates and alleged that the Restructuring Act did not intend to prevent such fuel clause adjustments in mandating the 10-15 percent rate reductions. In mid-2000, the DTE approved this approach and the resulting increases in SOS rates.

The Default Service pricing method relies entirely on passing through short-term wholesale market prices and has varied considerably since its onset in 2001, almost always higher than Standard Offer Service. Furthermore, as of March 2003, 36 percent of the residential customers were served under this higher rate, primarily due to the fact that customers who have moved or entered the service territory since March 1998 are not eligible for SOS. Competitive electric suppliers serve 2.4 percent of residential customers.^{xxii}

The following chart shows the impact of these pricing policies on regulated SOS and Default Service rates for residential customers in Massachusetts since the onset of restructuring:



After the price moderations that were in effect in early 2002, recent rate increases for Default Service customers were once again ordered by the DTE based on wholesale market prices in early 2003. As of May 1, 2003 through October 31, 2003, Massachusetts Electric Co. rates for residential customers will increase from 5.135 cents per kwh to 7.365 cents, a 44 percent increase in the price for the generation portion of the bill. Larger commercial and industrial customers will pay even higher rates, up to 8.6 cents per kwh in some cases. ^{xxiii}

Standard Offer prices have also increased, based on fuel adjustment filings by the utilities. The 2003 May-December price for Standard Offer rates for residential customers will vary from 5.6 cents per kwh to 5.852 cents at Boston Edison. ^{xxiv}

Legislative and Regulatory Developments. There have been no recent efforts to amend the Massachusetts restructuring law, even in light of the volatile prices for Default Service. Furthermore, the Massachusetts DTE remains firmly committed to the creation of a competitive market and the establishment of pricing methods that reflect “market” prices and “price signals,” defined as relatively short-term wholesale market prices. ^{xxv}

Furthermore, in a major policy decision, the DTE has issued an order to govern the pricing and purpose of Default Service in the future and after the expiration of SOS in 2005. ^{xxvi} The DTE based its decision on its overall intent to adopt policies that do not prevent the “most efficient market structure from

developing.” [Order at 33] With respect to procurement and pricing of Default Service, the DTE expressed a concern about bidding out 100 percent of each distribution utility’s default service supply every six months, recognizing that prices in the wholesale market can change quickly. As a result, the Department adopted the proposal by NSTAR to procure 50 percent of its default service supply semi-annually for 12-month terms. [Order at 45]

The Department also required the utilities to include information in its Default Service and Standard Offer service filing to describe the manner in which it has complied or intends to comply with its Renewable Portfolio Service obligation, but declined to set forth any minimum standards for a compliance strategy and specifically declined to require the utilities to enter into long-term contracts with renewable resources, even though comments in the proceeding made clear that such long-term contracts were required to support investments in such resources. Furthermore, the DTE refused proposals to require utilities to offer a “green” option for default service. [Order at 45-46]

Comments. The Massachusetts DTE’s approach to the design and pricing method for Default Service is crucial since ALL customers will be provided with this service at the end of the transition period in March 2005. While it characterized its change from 6-month to 12-month default service contracts as one that will contribute to more stable prices for residential customers, the significance of this change in preventing volatile wholesale market changes is not clear. Rather, this approach continues the process of refusing to develop long-term procurement options for Default Service supply and makes it very difficult to factor in cost-effective energy management or renewable energy resources into the Default Service supply mix. Massachusetts continues to rely on short-term wholesale market price changes.

PENNSYLVANIA

Background. Pennsylvania is one of the few states^{xxvii} that has attempted to bid out retail customers to default service providers, but generally without success. Under the Pennsylvania restructuring statute, electric distribution companies must provide default service to their customers during a lengthy transition period under a set of rate caps for both distribution and generation services that vary by individual utility.^{xxviii} In addition, several utilities agreed (under pressure from competitive suppliers, such as Enron, who have subsequently disappeared) to provisions in their restructuring settlements that required them to offer a portion of their customer load to the competitive market, thus awarding 20 percent of residential customers to a competitive supplier. However, the utility was not required to award any bids that exceeded the rate caps. As a result, the competitive bidding programs have required competitive suppliers to bid generation supply prices that were the same as or slightly below current rate caps for this service. Even so, such bidding would have the potential to award hundreds of thousands of residential customers to a competitive supplier without incurring any upfront marketing or acquisition costs.

Legislative and Regulatory Developments. Almost without exception, such bidding programs have not been successful, at least with respect to residential customers. Either the utility has received no qualifying bids or, in the case of the NewPower, the program failed when NewPower obtained approximately 300,000 residential customers from PECO but then withdrew when the supplier declared bankruptcy in 2002.

Under the most recent attempt to implement another PECO Energy settlement requirement, the Pennsylvania PUC approved a plan to assign 400,000 residential customers to alternative electricity suppliers.^{xxix} This “market share threshold plan” is to be implemented in two phases. In the first phase, winning bidders were supposed to serve 100,000 residential customers, who would be randomly assigned to licensed suppliers in the summer of 2003. Then, in the second phase, another bidding program will be held to assign the remaining pool of residential customers to new suppliers by December 2003. Bids for this service must provide at least a 1.5 percent discount from the current PECO Energy price for generation service for residential accounts. 20 percent of the customers will be assigned to suppliers offering service with a renewable energy component (containing at least 5 percent renewable resources), but bids for this service do not have to provide any discount from the current PECO generation price. Customers will receive notices about their assignment and be offered the option to decline the assignment and return to PECO without charge at any time. PECO will continue to handle all billing and customer contact, but the customer’s assigned generation supplier will be identified on the customer bill.

Under the Pennsylvania restructuring statute, the service that will be provided to those customers without a competitive provider is called the Provider of Last Resort service (the name for default service), but there are few statutory directions or details as to who must provide this service or how it should be priced. The Commission announced workshops in March 2003 to discuss the statutory requirement that distribution utilities or Provider of Last Resort suppliers are obligated to “acquire electric energy at prevailing market prices” and “recover fully all reasonable costs.” These Provider of Last Resort Working Groups held preliminary meetings, but the Staff did not propose any schedule for further meetings or other proposals that might structure future discussions.

Comments. As in Massachusetts, there has been no attempt to amend the Pennsylvania restructuring statute to clarify the intent and method of pricing Default Service. However, the presence of the rate caps and their longevity have prevented any adverse impact on customers due to the changes in the short-term wholesale market since the onset of restructuring. On the other hand, the Commission appears committed to fully exploring the competitive bidding structure to provide this service. The success of the PECO Energy assignment of customers under its May 1, 2003 Order may be the key to future developments in Pennsylvania. Preliminary results do not appear encouraging for this approach, however. The first round of bids for residential customers under Phase I of the program did not result in any bids. As a result, bids will be sought again in December 2003 for 375,000 residential PECO Energy customers. On the other hand, the bids solicited for small commercial customers was successful and 3 suppliers offered service to 65,000 small commercial customers at a 1.25 percent discount from the current generation service price offered by PECO Energy. Clearly, the notion of competitive bidding coupled with rate caps to assure affordable and stable prices for Default Service can result in benefits to customers and afford the opportunity to competitive suppliers to obtain a large number of retail customers without incurrent marketing and acquisition expenses.

ⁱ This paper builds on the research and recommendations set forth in Alexander, Barbara, Default Service For Retail Electric Competition: Can Residential And Low Income Customers Be Protected When The Experiment Goes Awry? (Oak Ridge National Laboratory, April 2002), available at NCAT’s website: <http://www.ncat.org/liheap/pubs/barbadefault3.doc> .

ⁱⁱ The Atlanta Gas Light retail competition program approved in Georgia in 1998 did not provide for any Default Service, allowing competitive suppliers to disconnect customers and leaving them without any regulated service provider. In 2002, the Georgia Legislature adopted amendments to the natural gas competition program that authorized the Commission to select a Provider of Last Resort to provide service at regulated rates. See NCAT’s September 2002 study that documents the impacts

of passing through short-term wholesale energy market rates to consumers in Georgia, Massachusetts, Ohio, Texas, and New York. <http://neaap.ncat.org/experts/mainintro.htm>.

ⁱⁱⁱ No State has adopted retail electric competition since 2000.

^{iv} Arizona, New Mexico, Nevada, California, Arkansas, West Virginia, and Oklahoma, have either adopted legislation or regulatory decision to halt or reverse the course to retail competition since 2000. Both Illinois and Virginia have extended transition periods for residential customers.

^v Sections 7-501 through 7-518 of the Public Utility Companies Article of the Annotated Code of Maryland.

^{vi} Maryland PSC, Order No. 77806, Case No. 8908, May 30, 2002.

^{vii} Maryland Public Service Commission, In the Matter of the Commission's Inquiry into the Competitive Selection of Electricity Supplier/Standard Offer Service, Case No. 8908, April 29, 2003.

^{viii} As a result, for example, the BGE obligation to provide SOS under the terms of the settlement will extend four years beyond the 2006 date contained in the restructuring settlement.

^{ix} Shorter service periods and more short-term wholesale market pass through mechanisms re established for larger commercial and industrial customers in the Settlement.

^x Montana PSC, Notice of Adoption, In the Matter of the Adoption of Rules Pertaining to Default Electricity Supply Procurement Guidelines, March 31, 2003.

^{xi} HB 509 was signed by the Governor on May 5, 2003, effective July 1, 2003, and assigned Chapter Number 565 of 2003 Session Laws.

^{xii} See http://www.dpuc-electric-choice.com/hotnews/new_list.html .

^{xiii} This amount was estimated as a total of \$14 million based on statewide sales by the Office of Consumer Counsel, who opposed this incremental charge.

^{xiv} Larger customers are not eligible for this service and must obtain their own generation supply or rely on the utility's "supplier of last resort" service" that reflects short-term wholesale market rates for a period of not less than one year.

^{xv} N.J.S.A. C.48:3-50 2(c)(4)

^{xvi} Perhaps not coincidentally, PSE&G is the only New Jersey utility that did not divest its generation assets.

^{xvii} I/M/O The Provision of Basic Generation Service, Decision and Order, Docket No. EX01050303, EO01100654, EO01100655, EO01100656, EO01100657, December 11, 2001.

^{xviii} I/M/O The Provision of Basic Generation Service, Decision and Order, Docket Nos. EX01110754 and EO02070384, December 18, 2002.

^{xix} Further emphasizing the wholesale nature of this transaction, all parties proposed that the auction process be coordinated to reflect the PJM scheduling timeframes, the local regional wholesale market.

^{xx} An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein, House No. 5117, November 19, 1997, ch. 164, Acts of 1997).

^{xxi} G.L. c. 164, Section 1B(d) and implemented in the Massachusetts DTE regulations, 220 C.M.R. Section 11.04.

^{xxii} Customer migration data is available from the Massachusetts Department of Energy Resources (DOER) website: www.state.ma.us/doer

^{xxiii} See <http://www.state.ma.us/dpu/restruc/competition/defaultservice.htm>

^{xxiv} See <http://www.state.ma.us/dpu/electric/sosfafilings.htm>

^{xxv} In rejecting the call of the Attorney General for adjudicatory hearings on the significant price increases for Default Service announced in April, the DTE stated that “reliance on efficient market prices leads to the best result for consumers.” See [citation needed]

^{xxvi} Massachusetts Department of Telecommunications and Energy, Investigation by the DTE on its own Motion into the Provision of Default Service, D.T.E. 02-40-B, April 24, 2003.

^{xxvii} Maine bids out the entire Standard Offer generation service for each customer class and for each distribution utility’s nonshopping customers in the wholesale market under the direct supervision of the Maine PUC. The distribution utilities are then required to enter into standardized contracts based on the PUC decision concerning the bids. The Maine PUC approved a 3-year bid for Standard Offer service to residential customers, effective March 2002. This program is unique among the restructuring states.

^{xxviii} The generation rate caps extend to 2009 for PPL, 2010 for PECO Energy, and 2010 for the FirstEnergy/GPU utilities.

^{xxix} Pennsylvania PUC, Petition for Approval of PECO Energy Company’s Market Share Threshold Bidding/Assessment Process, Docket Nos. P-00021984, P-00021992, Opinion and Order, May 1, 2003.