The Road to Electric Restructuring in Maryland

Department of Legislative Services
Office of Policy Analysis
Annapolis, Maryland

December 2006

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Department of Legislative Services
Office of the Executive Director
Maryland General Assembly

Karl S. Aro
Executive Director

December 31, 2006

The Honorable Thomas V. Mike Miller, Jr., President of the Senate
The Honorable Michael E. Busch, Speaker of the House of Delegates
Honorable Members of the Maryland General Assembly

Ladies and Gentlemen:

The Electric Customer Choice and Competition Act of 1999 restructured the electric utility industry in Maryland, introducing "customer choice" of an electric supplier effective July 1, 2000. As background, the first part of the report describes the circumstances, activities, and processes that led to the passage of the 1999 Act. Further, this part describes the transformation to retail choice since the passage of the Act, including the impact of price caps, the effect of significant price hikes of commodities used to generate electricity, and efforts to avoid rate shock as a result of price hikes.

The second part of the report describes the national status of retail access to electricity supply and compares Maryland's average retail price residential customers pay for electricity with other states that have restructured and with states that have not restructured. Like Maryland, many restructured states are still in a transition to full customer choice without price and other limitations. Accordingly, a complete comparison may be premature at this time.

The report was prepared by Tami Burt and Melanie Santiago-Mosier, with assistance from Robert Smith. The Department of Legislative Services trusts that the information will be useful to members of the General Assembly and to other persons interested in understanding Maryland's road to electric restructuring.

Sincerely,

Karl S. Aro
Executive Director

KSA/TDB/ncs

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Executive Summary

The advent of electric utility restructuring in the nation was part of the deregulatory trend that developed in the 1970s and spread through many previously regulated industries. The federally mandated transition to wholesale competition in electric generation and transmission prompted an interest in a transition to retail electric competition at the state level. For years, Congress debated enacting further legislation to influence the restructuring of the electric industry. In response to federal implementation of wholesale electric competition and legislation in some adjacent states allowing retail electric competition, the Maryland Public Service Commission (PSC) issued a series of orders to investigate implementing retail electric industry in Maryland. In 1997 the Maryland General Assembly created the "Task Force to Study Retail Electric Competition and the Restructuring of the Electric Utility Industry."

Prior to 1999, 12 states had enacted legislation requiring retail electric competition by a date certain and in one state the competent regulatory agency had issued a comprehensive regulatory order to implement electric competition. During 1999 and 2000, the last years in which any state enacted legislation to require retail electric competition, an additional 11 states plus the District of Columbia, including Maryland, joined the list of states that had authorized retail electric competition.

During the 1999 session, discussions culminated in the enactment of Chapters 3 and 4 of 1999, the "The Electric Customer Choice and Competition Act of 1999," to facilitate the restructuring of the electric utility industry. During the transition period, rates were reduced and capped for a period of time, giving the electric industry time to switch to a competitive market. However, competition was slow to enter the market with lower-than-market rates in effect under the rate caps. Although retail electric restructuring has primarily benefited big electricity users, suppliers only slowly started to enter the market for residential customers as the price caps expired. When price caps expire, customers become subject to market rates with the exact amount of increase depending on the final results of standard offer service (SOS) wholesale electric supply auctions.

In January 2005, the President of the Senate of Maryland appointed the Senate Special Commission on Electric Utility Deregulation Implementation to review the implementation of electric restructuring. The apparent results of electric restructuring in a climate of rising fuel costs appear mixed. The cost of fuel as a commodity used to produce electricity is the largest factor in total operating costs for most generation facilities. The hurricanes and other factors caused the price of natural gas to dramatically increase at the end of 2005, impacting the electric supply market. With the threat of significant electric price increases following the expiration of caps for Central Maryland, in January 2006 PSC instituted a case to ease the transition of BGE residential customers to market-based rates. At the same time, the General Assembly discussed making changes to the electric restructuring law. Over the course of the 2006 regular session, several legislative rate stabilization plans were developed for the BGE and PEPCO/Delmarva service territories.

After the failure of legislative rate stabilization plans at the end of the 2006 regular session, the General Assembly reconvened in Special Session in June 2006, to consider comprehensive legislation to address electric industry restructuring, SOS, rate stabilization plans, and the makeup of PSC. In the case of a significant increase in the retail cost of electricity for SOS between July 2006 and May 2007, Chapter 5 set a process to defer a portion of the increase with the deferred amount to be repaid in accordance with PSC proceedings. The deferral may be secured by bonds issued on behalf of the electric company and repaid in accordance with a qualified rate order. Although a truly competitive market had not developed, as of July 2006, BGE customers had at least eight plan alternatives to SOS, offered by five suppliers. Chapter 5 mandated several reports to assist the General Assembly in assessing the impact of electric restructuring on the State, and in altering it for the benefit of consumers.

The U.S. Energy Department reported in October 2006 that the outlook in natural gas prices forecasts a decline in natural gas prices. Since the wholesale electricity market is heavily influenced by movements in the natural gas market, when local electric companies go to the SOS auction to secure their power load effective June 1, 2007, lower electric prices are anticipated.

The national status of retail access to electricity supply has been relatively unchanged for several years. At this time, 16 states and the District of Columbia have fully implemented legislation and commission orders to allow full retail access for all consumer groups. In addition to the California power crisis, the electricity supply industry has been plagued by other problems that will likely further discourage electricity market restructuring.

From 2002 to 2005, the national average residential retail price of electricity rose 11.35 percent. For the same time period, the states that have maintained a regulated electricity supply market saw average prices increase at a rate nearly identical to the national average, approximately 11.30 percent. In the five restructured jurisdictions whose transition period to a market structure had ended by 2005, residential prices generally increased faster than the national average. However, numerous states that did not restructure experienced rate increases over the national average.

An analysis of more recent changes in residential electricity rates shows an interesting trend. From the months of January through July of 2005 to January through July of 2006, the national average residential retail price of electricity rose 11.83 percent, only slightly higher than the rise the nation had seen from 2002 to 2005. For the same time period, 8 of the 16 states with a restructured electricity supply market saw increases that were above the national average. However, four states that did not restructure also experienced rate increases above the national average. Maryland's rates rose 10.70 percent, less than the national average.

A regional analysis of electricity price increases for the year-to-date from July 2005 to July 2006 also presents interesting data. During this one-year period, the New England census division saw average residential rates increase at a rate of 23.36 percent, nearly double the national average. The Mountain census division saw the smallest increases, with an average of only 4.20 percent. The West South Central, Pacific Contiguous, and Pacific Noncontiguous census divisions all experienced average residential electricity price increases above the national average. The Middle Atlantic, East North Central, West North Central, South Atlantic, and East South Central divisions experienced price increases below the national average.

An analysis that compares only average residential prices is incomplete. When comparing the retail price of electricity across markets, it is necessary to consider the factors contributing to the end-use cost. Aside from the systematic components, the major factors that determine the retail price of electricity are the cost and availability of fuel used for power generation; the construction costs of generation plants and the associated expenses for operation and maintenance; supply and demand for fuel and transmission; international events; and weather changes. Natural gas prices are often cited as one of the leading factors impacting retail electricity prices, particularly in states that have restructured their electric supply markets.

As stated earlier, from 2002 to 2005, the national average residential retail price of electricity rose by 11.35 percent. West Virginia actually experienced a slight decrease of less than one-half of 1 percent. New York had increases that were greater than the national average, at 16 percent. For Maryland, Delaware, and Virginia, in 2005 most of the residential electricity prices were still controlled through rate caps during the transition to retail access to electricity supply. The average residential price increases for these states were 6.33 percent, 3.68 percent, and 4.49 percent, respectively. During this time period, New York and Vermont generally had prices well above Maryland's. West Virginia had prices below Maryland's.

As stated earlier, from July 2005 to July 2006, the national average residential retail price of electricity rose by 11.83 percent. Delaware had increases that were greater than the national average, at nearly 20 percent. For Maryland and New York, increases were below 11.0 percent. North Carolina's increase was 5.7 percent, while Vermont and Virginia experienced increases of 4.16 and 3.83 percent, respectively. West Virginia's increase from July 2005 to July 2006 was the smallest in the nation at just over one-half of 1 percent.

As of July 2006, Maryland ranks thirtieth nationally in terms of the average retail price residential customers pay for electricity. Delaware ranks fifteenth; New York has the third highest average residential rates nationally; North Carolina ranks twenty-sixth; Vermont is ranked tenth; Virginia ranks thirty-fourth; and West Virginia ranks fiftieth, with rates higher than only Idaho.

The Road to Electric Restructuring in Maryland
Part 1

The advent of electric utility restructuring (also known as deregulation) in the nation was part of the deregulatory trend that developed in the 1970s and spread through many previously regulated industries, including the airlines, banks, motor carriers, railroads, and telephones. In the electric utility industry context, "restructuring" separated the historically vertically integrated monopolies that provided electricity to all customers into three distinct services: generation, transmission, and distribution. Restructuring then freed the generation service from its traditional rate-of-return rate-setting regime, while also simplifying the regulation of transmission and distribution services. This section describes the circumstances, activities, and processes that led to electric restructuring in Maryland.

Federal Activities Prior to 1999

The federally mandated transition to wholesale competition in electric generation and transmission, as provided in a sequence of enacted legislation and orders, prompted an interest in a transition to retail electric competition at the state level. The federal activities are described below.

- Congress passed the Public Utility Holding Company Act (PUHCA) (former 15 U.S.C. § 79 *et seq.*) in 1935, establishing a comprehensive regulatory structure regarding the operations of public utilities. PUHCA was enacted to break up large and powerful trusts that controlled the electric and gas distribution networks at that time. PUHCA's restrictions generally applied to multi-state utility companies that were organized in a holding company structure. Congress also passed the Federal Power Act which provided the Federal Energy Regulatory Commission (FERC) the authority to regulate utilities involved in the interstate wholesale transmission and sale of electric power.

  However, in 2005, Congress repealed PUHCA in the 2005 Energy Policy Act (*see below*). As a result, at this time there are no longer any federal restrictions, including geographic limitations, as to who can buy or consolidate with an electric or gas public utility. Accordingly, holding companies may own both a public utility and nonutility business. FERC retains the authority to review mergers and acquisitions in the energy utility market.

- The Public Utility Regulatory Policies Act (PURPA), passed in 1978 in response to the unstable energy climate of the late 1970s, sought to promote conservation of electric energy as an alternative to expansion of traditional, regulated electric utility facilities. PURPA mandated that existing regulated utilities purchase power from certain nonutility "qualifying facilities." Under PURPA, qualifying facilities include not only power producers that use alternative energy sources, but also co-generators that use fossil fuel-fired steam turbines to generate both electricity and useful thermal energy in the form of steam.

- The first Energy Policy Act (EPAct), passed in 1992 to amend the Federal Power Act, comprehensively reformed the electric utility industry by promoting competition in wholesale electric power markets. The EPAct authorized FERC to order utilities to provide open access to their transmission lines to other utilities, nonutilities, and other wholesale providers and suppliers of electric power. FERC has jurisdiction over these wholesale "wheeling" transactions and approves rates filed by each utility for transmission to ensure that the amount charged to others is no more than the utility is charging itself.

- Charged with ensuring that resources of the electric industry are used wisely, efficiently, and in the public interest, in 1996 FERC adopted rules to implement the open access provisions of the EPAct. FERC issued two separate but interrelated orders (Orders 888 and 889, dated April 24, 1996) to encourage wholesale competition. FERC also issued a Merger Policy Statement on December 18, 1996 (Order 592) to revise its standards for evaluating proposed mergers of public utilities.

  - Order 888 addressed the issues of open access to the transmission network and stranded costs. Transmission-owning utilities must offer transmission service to all eligible customers on a nondiscriminatory basis. To ensure this result, utilities were required to file open access transmission tariffs that contain minimum terms and conditions of service. Utilities were required to unbundle wholesale transactions and take transmission services under the same tariffs with which they serve others, separately pricing each service. Recognizing that there would be costs associated with the transition to wholesale competition, utilities were allowed to seek recovery of legitimate, prudent, and verifiable costs that may be stranded because their customers use open access transmission service to obtain power from other generation sources.

  - Order 889 required utilities to establish electronic systems to share information about available transmission capacity and prices.

For years, Congress debated adopting further legislation to influence the restructuring of the electric industry. During calendar 1997, bills were introduced to mandate retail electric utility competition in all states (one bill would have required it by early 2000 and another by late 2003); address market power; support a nationwide surcharge for systems benefits such as energy efficiency and low-income programs; set controls to prevent increases in pollution with electricity deregulation; require renewable energy portfolio standards; and require utilities to disclose to consumers their sources of generation, emissions, and price. Other bills would have deferred to the states whether to implement restructuring, while giving FERC authority to order open access for power marketing authorities and municipal and rural cooperative electric utilities.

Under Order 888, the question of whether a state or federal agency has jurisdiction over a retail electric transaction is determined by analyzing whether the regulated activity is classified as transmission or distribution. The states' public service commissions have jurisdiction over distribution, as well as transmission as long as the services are bundled. Once the services are unbundled and retail electric competition is allowed, the states' public service commissions only regulate distribution, while federal authorities regulate transmission.

Maryland Public Service Commission Efforts Prior to 1999

Since 1910 the Maryland Public Service Commission (PSC) has been delegated the authority by the Maryland General Assembly to regulate utilities operating in Maryland. During the mid-1990s, in response to federal implementation of wholesale electric competition and legislation in some adjacent states allowing retail electric competition, PSC issued a series of orders to investigate the issue of implementing a retail electric industry in Maryland. See **Appendix 1** for a complete list of PSC orders relating to electric restructuring.

- In September 1994, PSC by order began to review the issues surrounding the restructuring of the retail electric industry. Although PSC determined in August 1995 that the introduction of retail electric competition was not in the public interest at that time, PSC continued to monitor and evaluate State and national developments in the electric industry.

- In October 1996, PSC directed its staff to make recommendations on the issues regarding retail electric competition. In May 1997, PSC staff issued *A Framework for Customer Choice and the Future Regulation of Electric Services in Maryland* that contained many recommendations regarding the transition to a competitive retail market for electric power in Maryland. After receiving comments from interested parties, PSC by order in early December 1997 established a process that moved toward allowing the restructuring of the retail electric industry, including the introduction of legislation in the 1998 session.

- As a result of issues filed on the timing of the phase-in specified in the December 1997 order, PSC issued a subsequent order in late December 1997 to delay each of the implementation dates for customer choice by 15 months and suspend the mandated filing dates and commencement dates for the various adjudicatory hearings and roundtable proceedings, pending further action by PSC. That order specified that retail electric competition would be phased in beginning in July 1, 2000, to be fully available to all Maryland residents and businesses by July 1, 2002. There would be two one-year prototype programs with limited levels of customer participation (the first would include

33 1/3 percent of the total load served in each customer class; the second year would increase to 66 2/3 percent).

PSC determined that achieving a successful transition from a regulated to a competitive electric industry needed to incorporate both adjudicatory hearings and roundtable proceedings involving groups of interested parties that would identify contentious issues and seek to resolve them through structured settlement discussions. The order specified that a price cap would be implemented from April 1, 1999 to April 1, 2001; utilities would be required to identify their stranded costs by March 6, 1998; and PSC would initiate an adjudicatory proceeding to resolve the matter of stranded costs and whether a distribution wires charge (commonly called a competitive transition charge) needed to be imposed.

1997 Task Force

In light of federal, PSC, and other states' activities, in 1997 the Maryland General Assembly created a 20-member "Task Force to Study Retail Electric Competition and the Restructuring of the Electric Utility Industry" (Chapter 106 of 1997). The task force consisted largely of State senators, delegates, and representatives of the Executive Branch. The task force was charged with conducting hearings to solicit comments and recommendations; evaluate the impact of implementing retail electric competition and the restructuring of the electric industry on Marylanders; review activities in other states; evaluate associated tax and regulatory issues; and determine the impact on social, environmental, and other public service functions. In order to assist the task force in its deliberations, the Act required the Governor, the President of the Senate, and the Speaker of the House of Delegates jointly to appoint an advisory group consisting of industrial, commercial, and residential electric customers; investor-owned electric utilities, electric cooperatives, municipal electric systems, and an independent power producer; and the solar and coal industries.

The task force met almost every other week from mid-September 1997 to mid-December 1997, and heard briefings from representatives of federal agencies, Maryland State agencies and local jurisdictions, customer groups, utility providers, other states, and other interested parties. The task force heard about the possible benefits and costs of allowing retail electric competition. Issues presented and discussed during meetings included market power, unbundling services and rates, stranded and transitional costs, tax implications, consumer concerns, reliability and safety issues, and environmental concerns. Although the task force did not issue a final report, the issues continued to be discussed in the legislature for many years.

Other States' Activities Prior to 1999

Prior to 1999, 12 states had enacted legislation requiring retail electric competition by a date certain, and in one state the competent regulatory agency had issued a comprehensive regulatory order to implement electric competition. The remaining states, with the exception of Florida, Kentucky, Nebraska, and South Dakota, were reviewing retail electric competition either through pending legislation, pending regulatory public service commission orders, or other types of ongoing investigation.

During 1999 and 2000, the last years in which any state enacted legislation to require retail electric competition, an additional 11 states plus the District of Columbia, including Maryland, joined the list of states that had authorized retail electric competition. Legislation enacted or orders issued in all of the 24 states and DC had similar provisions, including a phase-in period and rate caps. Most of the states (10) were considered as high-cost states, 7 plus DC as low-cost states, and 7 as average-costs states (includes Maryland). See **Appendix 2** for a list of these states.

Maryland's 1999 Legislation

As PSC began its roundtable working groups in 1998, the General Assembly continued its discussions regarding retail electric competition that had surfaced with the 1997 task force. In 1999, these discussions culminated in the enactment of Chapters 3 and 4 of 1999, "The Electric Customer Choice and Competition Act of 1999," to facilitate the restructuring of the electric utility industry.

Under the Act, electric restructuring consisted of a phase in of "customer choice" for all investor-owned utilities, along with customer protections, a new universal service program for low-income customers, and environmental protections that addressed a restructured electric framework. See **Appendix 3** for a complete summary of the 1999 Act.

The primary feature of the electric utility industry restructuring was the introduction of customer choice effective July 1, 2000. Prior to restructuring, also known as deregulation, the local electric utilities were vertically integrated monopolies. In this regulatory system, in place since the 1930s, the electricity industry provided a unitary regulated service. For jurisdictional purposes, the service was divisible into three main components:

- *generation* of electricity;
- *transmission* of that electricity on high-capacity lines to distribution networks; and
- *distribution* of the transmitted electricity to customers.

Each electric utility company then would "bundle" these three services and provide them to its customers within its geographically defined monopoly service territory. PSC had authority to approve rate increases affecting all three components while FERC also had concurrent authority over the transmission service. Approved rate increases were based on the cost of producing power plus a reasonable profit.

Restructuring took the generation component out of the combined service package through "unbundling," which formally separated the three component services into distinct identified and billed commodities. Although the generation component is deregulated as to price, the transmission and distribution components remain regulated as monopoly services. The resulting customer choice allows a customer to purchase electricity generated by other sources and have the electricity delivered over transmission and distribution lines of the local electric utility. A customer has the option to remain with its distribution provider, the incumbent electric utility, as its supplier of generation service under "standard offer service (SOS)." SOS is electricity purchased from the local electric utility that distributes electricity to the customer. The local electric utility buys power from producers that compete in the wholesale market to offer electricity at the lowest price. As leaner, efficient power plants win the wholesale contracts over costly plants, the savings would be passed on to customers.

Under the Act, until July 1, 2003, for investor-owned utilities and July 1, 2005, for cooperatives, each electric company had the obligation to offer SOS, at the regulated capped rate, to a customer who (1) did not choose a new electric supplier; (2) was not offered customer choice; (3) contracted for outside electricity supply that is not delivered; or (4) was denied service by an electric supplier. After July 1, 2003, if the electricity supply market was not competitive or if PSC had not received an acceptable competitive proposal for supplying SOS, PSC was required to extend the current obligation to serve, at a market price sufficient to provide the electric company with the opportunity to recover verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return.

Although the Act established a phase in of "customer choice," PSC was authorized to alter the implementation schedule by order or settlement agreement with each electric company. The adopted schedules under orders made by PSC during 2000, including the approximate number of residential customers that each utility serves in Maryland as of September 2006, are as follows:

- All customers of investor-owned utilities had access to customer choice as of July 1, 2000. The four large investor-owned utilities are:

  Baltimore Gas and Electric Company (BGE), 1.1 million;
  Delmarva Power and Light Company (Delmarva), 173,000;
  Potomac Edison Company (Allegheny Power), 213,000; and
  Potomac Electric Power Company (PEPCO), 471,000.

- For electric cooperative customers, access to customer choice began July 1, 2003. The four electric cooperatives are:

  A&N Electric Cooperative;
  Choptank Electric Cooperative, 41,000;
  Somerset Rural Electric Cooperative; and
  Southern Maryland Electric Cooperative (SMECO), 123,000.

- Municipal electric utilities were not required to allow customer choice unless the utility elected this option and filed a plan and schedule with PSC. The five municipal electric utilities as of 1999 were:

  Berlin Municipal Electric Company, 1,600;
  Easton Utilities Commission, 8,000;
  Hagerstown Municipal Electric Light Plant, 15,000;
  St. Michaels Utilities Commission
  (*Note: acquired in 2006 by Choptank Electric Cooperative*);
  Thurmont Municipal Light Company, 2,500; and
  Williamsport Municipal Electric Light System, 800.

The 1999 Act enacted two mechanisms to protect customers from rate swings during the transition to electric restructuring: a mandated rate reduction and a rate cap. For residential customers of investor-owned utilities, the Act mandated a rate reduction, beginning July 1, 2000, of 3.0 to 7.5 percent of base rates as measured on June 30, 1999. Rates were capped through July 30, 2003. PSC allocated the rate reduction among generation, transmission, and distribution components of residential electric rates, thus giving a portion of the rate reduction to customers who chose a different generation supplier as well as those who remained with SOS.

Implementation of the 1999 Act

Through settlement agreements between the utilities and interested parties and approved by PSC through orders in 2000, alternative rate requirements for distribution service and SOS were negotiated with six of the utilities that provide in-state electric services. See **Appendix 4** for a summary of these alternative rate requirements.

- For PEPCO, Delmarva, and BGE residential customers, the timing for SOS caps coincided with the timing for distribution service restrictions. For PEPCO (with a 7 percent rate reduction) and Delmarva (with a 7.5 percent rate reduction), both SOS and distribution rate caps began July 1, 1999, and expired June 30, 2004; for BGE (with an average 6.5 percent rate reduction), SOS and distribution rate caps began July 1, 1999, and expired June 30, 2006.

- Allegheny Power (with a 7 percent rate reduction) capped its residential distribution rate from July 1, 1999 through December 31, 2004, but capped its residential SOS rate from July 1, 1999 through December 31, 2008.

- SMECO capped its residential distribution rate from July 1, 1999 through December 31, 2004, after which rates were to be set by PSC through December 31, 2008; it froze its residential SOS rate from July 1, 1999 through December 31, 2004, after which it began to offer the service at market-based prices through December 31, 2008.

- Choptank Electric Cooperative capped its residential distribution rate from July 1, 1999 through June 30, 2005, and froze its residential SOS rate from July 1, 1999 through June 30, 2005, after which it began to offer the service at market-based prices through June 30, 2010.

Settlement agreements adopted by PSC in 2003 extended the obligation for each investor-owned local electric utility to provide SOS for four additional years (through May 31, 2008, for PEPCO and Delmarva; through May 31, 2010, for BGE; and through December 31, 2012, for Allegheny).

One of the most complex issues in restructuring the electric utility industry was how to treat transition costs or benefits, the difference between the book value and market value of an electric company's generation assets. Although under the restructuring law an electric company might recover certain prudently incurred transition costs (known as "stranded costs"), it could only do so under a commission-approved transition plan developed in accordance with fact-finding and evidentiary proceedings, and subject to full mitigation. Under settlement agreements (between the utilities and interested parties) approved by PSC in 2000 through orders:

- BGE recovered $528 million of transition costs over a four- to six-year period, with commercial customers paying about 63 percent and residential customers paying the remaining 37 percent of these costs;

- PEPCO returned $188 million of transition benefits, with commercial customers receiving about 60 percent and residential customers receiving the remaining 40 percent of the savings;

- Delmarva recovered $8 million of transition costs from commercial customers; and

- Allegheny recovered costs for the buy-out or buy-down of its power purchase contracts at the Warrior Run Power Plant facility in Cumberland.

To assist with other aspects of the 1999 Act, PSC instituted seven working groups, dealing respectively with consumer education, universal service, supplier authorization, consumer protection, competitive billing, demand side management, and generic technical implementation. PSC held hearings and received comments from interested parties on the recommendations of the working groups and issued orders in 1999 and 2000 on the recommendations, which included some modifications to the recommendations. As many of the issues were complex, PSC had to resolve a variety of matters on which the working groups could not reach consensus. See Appendix 1 for a complete list of PSC orders relating to electric restructuring.

Suppliers Are Slow to Enter the Competitive Market

During the transition period to retail electric competition, rates were reduced and capped for a period of time, giving the electric industry time to switch to a competitive market. However, competition was slow to enter the market with lower-than-market rates in effect under the rate caps. Although under the Act, the rate cap period was an important element of the overall transition to competitive markets, in the event alternative electricity suppliers could not compete with the incumbent electric company (*e.g.*, through a settlement agreement approved by PSC, BGE rates were reduced to 1993 levels and capped for six years while market-based generation costs were generally increasing).

Although retail electric restructuring has primarily benefited big electricity users, such as industrial customers and State and local government operations, suppliers only slowly started to enter the market for residential customers as the price caps expired. For residential customers, in fiscal 2006, 57 companies were licensed with PSC as suppliers in the State. Although approximately 20 suppliers are licensed in each of the BGE, Delmarva, and PEPCO service territories, only 6, 1, and 3, respectively, are actively seeking new residential customers. **Exhibit 1** shows the electricity suppliers in Maryland that are actively seeking new customers by customer class and service territory, and the total number of suppliers licensed to provide services to those customer classes in those territories.

Exhibit 1
Electricity Suppliers Active and Licensed in Maryland by Service Territory
Fiscal 2006

Service Territory **Active**/*Total Licensed*	Residential		Commercial		Industrial		Other	
Allegheny	**0**	*19*	**17**	*48*	**17**	*43*	**9**	*13*
BGE	**6**	*22*	**27**	*57*	**26**	*50*	**9**	*14*
Delmarva	**1**	*20*	**22**	*54*	**22**	*48*	**9**	*14*
PEPCO	**3**	*21*	**24**	*54*	**23**	*48*	**9**	*14*
SMECO	**0**	*4*	**0**	*8*	**0**	*8*	**0**	*3*
Choptank	**0**	*2*	**0**	*4*	**0**	*4*	**0**	*1*

Note: The first figure for each customer class, in **bold**, is the number of active suppliers in that customer class in the service territory; the second figure, in *italics*, is the number of electricity suppliers licensed to serve the customer class in the service territory. The latter figure includes anyone licensed as any kind of "electricity supplier" (a supplier, aggregator, broker, or biller). It also includes any electricity supplier with a currently valid license, whether or not the supplier is now or has ever served customers in the State.

Source: Public Service Commission

Initial Auctions – PEPCO and Delmarva

When price caps expire, customers become subject to market rates. The exact amount of increase depends on the final results of SOS wholesale electric supply auctions. The auction mechanism and related features of customer choice have been implemented through PSC orders and regulations. Two orders, entitled "Phase I" issued at the end of April 2003 and "Phase II" issued at the end of September 2003, respectively, establish a framework for competitive wholesale supply procurement and procedures for the procurement and pricing of SOS following the end of the investor-owned utility generation rate cap periods.

The wholesale electric supply is procured using a bid request process for the SOS retail local obligations of each utility. Suppliers bid for a specified percentage of full requirements service load (energy, capacity, and transmission services) during a particular delivery period which includes changes in customer demand for any reason. Before submitting bids, suppliers and utilities exchange various information and suppliers undergo an eligibility review process. The process encompasses multiple tranches (a "tranche" is portion of service load offered in a bidding round) on staggered dates to procure the wholesale electric supply. To attract bidders, the load is divided into 50-megawatt bid blocks, which represent a specified percentage of the associated SOS load of the utility. Bid blocks are by a variety of single-year and multi-year contracts and are for a specified service (*i.e.*, summer, nonsummer, peak, and nonpeak load). All other terms are uniform. Bid block offers with the lowest price are selected.

When setting prices, suppliers consider the prices in the wholesale spot market operated by the PJM Interconnection. Located in Valley Forge, Pennsylvania, PJM is a regional transmission organization that plays a vital role in the U.S. electric system. PJM ensures the reliability of the largest centrally dispatched electric grid in the world by coordinating the movement of electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Acting neutrally and independently, PJM operates the largest competitive wholesale electricity market in the world; it manages a sophisticated regional planning process for generation and transmission expansion to ensure future electric reliability. Further, it facilitates a collaborative stakeholder process which includes participants who produce, buy, sell, move, and regulate electricity.

The grid operator daily solicits bids on the spot market from power generators to fill the expected electricity demand for the next day. Lowest bids are accepted first, typically from nuclear and coal-fired power plants. If those plants cannot meet the demand (*e.g.*, high temperature days of summer), PJM accepts bids from more expensive natural gas and oil plants. Similar to other commodity markets, the last (and most expensive) bid is the price paid to all producers, regardless of the actual fuel they use to generate the electricity.

For residential customers, PEPCO and Delmarva price caps expired on June 30, 2004. The bid request process adopted by PSC in Phase I and II was used for PEPCO and Delmarva residential SOS for the July 1, 2004 through May 31, 2005, and June 1, 2005 through May 31, 2006, service years. For the initial SOS procurement to solicit bids to serve load for July 1, 2004 through May 31, 2005, the bidding rounds began in February 2004 and concluded in March 2004; approximately 6,200 megawatts (MW) were available for bid. For the second SOS procurement to solicit bids to serve load for June 1, 2005 through May 31, 2006, the bidding rounds began in December 2004 and concluded in February 2005; approximately 3,590 MW were available for bid (about 29 percent of the load was residential one-year contracts and the remaining Type I and II nonresidential one-year contracts). There were 20 eligible bidders of which 18 suppliers actually submitted bids and 9 suppliers won some portion of the load offered. The average total bills (based on a monthly 1,000 kWh user) for residential customers increased for the July 1, 2004 through May 31, 2005, period by 16 percent for PEPCO and 12 percent for Delmarva and for the June 1, 2005 through May 31, 2006, period by 4.5 percent and 5.8 percent, respectively. See **Appendix 5** for a summary of the increases during these periods.

As discussed below, the bid request process was also used for PEPCO and Delmarva residential SOS for the June 1, 2006 through May 31, 2007, service year, and for BGE residential SOS for the July 1, 2006 through May 31, 2007, service year.

SMECO Portfolio Management

SMECO is the major distributor of electricity in Southern Maryland, serving approximately 123,000 residential customers. It owns and operates transmission and distribution facilities in Charles, Calvert, St. Mary's, and southern Prince George's counties. Unlike an investor-owned utility, the cooperative is owned directly by all of its customers, and any profits accrue as dividends to the customers. Traditionally, electric cooperatives deliver electricity at lower costs than investor-owned utilities, in part because net earnings are paid back to customers rather than to a separate class of shareholder investors.

Because SMECO owns no generation assets, it has always had to procure electricity from suppliers. Under the former regulated regime, an electric cooperative would procure electricity from one or more nearby utilities under long-term contracts subject to review by PSC. Because of the risks associated with an electricity market facing instability in fuel supply and pricing, SMECO adopted a "portfolio management" procurement strategy. Under this strategy, SMECO procures electricity contracts over varying terms from several different generation sources. Although this might not produce the absolute lowest price for a given period, over time the blending of contracts is intended to spread the risk of increased prices based on fuel costs and other factors over the long term. This method is intended to produce a result similar to that of the SOS auction system for investor-owned utilities, although without the strict market-power oversight mechanism required of the latter process by PSC. Further, rates are adjusted monthly. If SMECO fails to procure enough long-term power to meet its needs, it bears the risk of making up any shortfall at higher cost on the spot market. SMECO uses a risk management company associated with its national association to assist with procurement of its managed portfolio procurement.

The announcement of a 22 percent price increase in the SMECO service territory in late 2004 (effective January 1, 2005, when rate caps expired) was one of the factors leading to the establishment of the Senate Special Commission on Electric Utility Deregulation Implementation (discussed below). See Appendix 5 for the impact on prices January 2005 through April 2006.

Senate Special Commission on Electric Utility Deregulation Implementation

In January 2005, the President of the Senate of Maryland appointed the Senate Special Commission on Electric Utility Deregulation Implementation. Although the President indicated that Maryland electric restructuring law had been held up as a model by legislatures pursuing similar laws nationally, he charged the special commission with assessing its progress and making recommendations for improvements or modifications to ensure that the intent of the law for a competitive market leading to lower electric utility rates would be achieved.

During its five meetings during the 2005 interim, the special commission heard briefings regarding the status of the implementation of the law; the process of procuring SOS power for investor-owned utilities and electric cooperatives, including SMECO's portfolio management procurement strategy; a proposal to allow a pilot opt-out aggregation program; the process for rate making and the rising costs of commodities used to generate electricity; the experiences in other states with retail market competition; the unintended impact of the 1999 Act on Eastalco (a large industrial user) in directly procuring power; the competition of the wholesale electric supply market and the implications of the recent federal energy legislation; and the progress of Mirant in its bankruptcy proceedings. The special commission also visited PJM's headquarters to learn how it ensures reliability of electricity in all or part of 13 states and the District of Columbia.

The special commission continued to meet during the 2006 session. On several occasions, the special commission discussed the numerous bills that were introduced to make changes to the electric restructuring law. At the same time, these bills were also being thoroughly discussed by the Senate Finance Committee (5 of the 11 special commission members were also members of the Senate Finance Committee), as well as by the House Economic Matters Committee. Accordingly, instead of issuing a separate final report with recommendations, the commission deferred its work product to the Senate Finance Committee. Members of the special commission were invited to participate in Senate Finance Committee discussions.

Significant Price Hikes of Commodities Used to Generate Electricity

The apparent results of electric restructuring in a climate of rising fuel costs appear mixed. The cost of fuel as a commodity used to produce electricity is the largest factor in total operating costs for most generation facilities. Although electric restructuring under the 1999 Act was expected to reduce electricity prices for most consumers, a number of factors in the intervening years have combined instead to increase the price of electricity nationwide. The restructuring of generation promised to increase opportunities for independent generators to build new, more efficient power plants using natural gas as the clean, economical fuel of choice. However, the Enron scandal and the failure of a poorly designed restructuring law in California scared many investors away from financing new generator construction. The cost of fuels increased with demand for these commodities on the world market and the impact of natural disasters. Market prices for natural gas and fuel oil increased far beyond what had been anticipated when the 1999 Act was enacted or when orders specifying the SOS auction process were being finalized by PSC in 2003. For example, the price of natural gas increased to an all-time high spot-market price exceeding $18 per million BTU in part due to the reduction of supply caused by Hurricanes Katrina and Rita in the autumn of 2005.

When the hurricanes and other factors caused the price of natural gas to dramatically increase, the impact was quickly realized in the electric supply market. PJM had to accept bids on the spot market to fill the expected electricity demand from a much more expensive natural gas. Since the last (and most expensive) bid is the price paid to all producers, the price of natural gas ended up dramatically influencing the price of power and, therefore, the price suppliers bid in the auctions (as shown below for the 2006-07 bidding auctions for residential SOS rates).

PSC's *Ten-Year Plan (2005-2014) of Electric Companies in Maryland* issued in December 2005 describes the percentage of Maryland generating profile capacity used in the PJM region by primary fuel type (a total of 12,486 MW of summer peak capacity), as compared to the percentage of actual generated by primary fuel type in 2003, as follows:

- coal plants represent about 40 percent of the total Maryland summer peak capacity (but, coal plants actually generated 57 percent of the total electricity consumed);

- dual-fired (petroleum and natural gas), natural/other gases, and petroleum plants represent about 41 percent of the total Maryland summer peak capacity (but, these fuel types actually generated 10 percent of the total electricity consumed) – the high cost of these fuel types causes these plants to be used as peak plants;

- nuclear plants represent about 14 percent of the total Maryland summer peak capacity (but, nuclear plants actually generated 26 percent of the total electricity consumed); and

- hydroelectric and other renewables plants represent about 5 percent of the total Maryland summer peak capacity (but, these fuel types actually generated 7 percent of the total electricity consumed).

Under the regulatory framework in place prior to the 1999 Act, fuel cost changes were generally passed through directly to customer rates in accordance with a fuel-adjustment mechanism without direct PSC involvement. Accordingly, the old regulatory framework might not have shielded customers from bearing the cost of high fuel prices in the wake of the 2005 hurricanes and increased fuel commodities.

Efforts to Avoid Rate Shock from the 2006 Auction

Because of significant increases in the prices of commodities used to generate electricity in late 2005, it become evident by early 2006 that SOS rates would significantly increase for the service period beginning June 1, 2006, for PEPCO and Delmarva residential customers and the service period beginning July 1, 2006, for BGE. The magnitude of the increase was much more dramatic on BGE customers whose rate caps were due to expire at that time; PEPCO and Delmarva's rate caps had expired two years earlier.

The third SOS procurement cycle, which solicited bids to serve load for 2006-07, conducted bidding rounds in November and December 2005 and concluded in January 2006. Approximately 7,540 MW of one-, two-, and three-year contracts were bid (of which 64 percent was residential and the remaining Type I and II nonresidential load). As a result of the auctions, the total electric bill for an average residential customer (1,000 kWh per month) increased by:

- 35.0 percent on June 1, 2006, in the Delmarva service territory (previous two-year increases were 19.0 and 5.8 percent);
- 39.0 percent on June 1, 2006, in the PEPCO service territory (previous two-year increases were 16.0 and 4.5 percent); and
- 72.0 percent on July 1, 2006, in the BGE service territory.

See Appendix 5 for a summary of these increases during this time period.

With the threat of significant electric price increases following the expiration of caps for Central Maryland, and as directed by the Governor, on January 10, 2006, PSC instituted a case to ease the transition of BGE residential customers to market-based rates. PSC staff developed a mitigation plan that PSC then adopted on March 6, 2006. Initial increases under that plan would have been limited to 21 percent. The plan included carrying costs to compensate the utility for financing costs associated with the regulatory asset of the deferred cost of delivered electricity. Customers who did not want to participate would have had to affirmatively reject the mitigation plan. The mitigation plan would have been administered through the delivery service portion of the bill to be competitively neutral. The plan would have commenced June 1, 2006, and ended May 31, 2008. For the initial nine months, customers who participated would have had their bills mitigated to below-market increases, with the customer bill showing both the actual usage and the deferred amounts. Following this period, the deferred amounts would have been recovered in customer bills over the succeeding 14-month period. Shortly thereafter, PSC also adopted a similar simpler plan for the PEPCO and Delmarva service territories.

At the same time PSC was developing a plan, the General Assembly discussed making changes to the electric restructuring law. Over the course of the 2006 regular session, several legislative rate stabilization plans were developed for the BGE and PEPCO/Delmarva service territories. Because of the magnitude of the proposed 72 percent increase in residential rates in the BGE service territory, that area received the greatest attention. While several legislative proposals were considered (most notably, House Bill 1525 and House Bill 1712 of 2006), none passed both chambers during the 2006 regular session.

Subsequently, the PSC staff proposal for the BGE service territory was modified and approved as the so-called "Governor's plan" on April 28, 2006. This plan would have provided a more gradual implementation of full SOS market rates – a 19.4 percent increase initially, with a second-step 5 percent increase on January 1, 2007; on June 1, 2007, customers would have begun to repay the deferred amount (a 25 percent rate increase was anticipated to begin on June 1, 2007). Further, the modification would have allowed for an "opt-in" method and a lengthening of the deferred payment period, and a grace period for customers to enroll if they miss the initial enrollment period. Customers would have moved to full-market rates January 1, 2008 (with an estimated 9 percent increase), with payment of deferred amounts continuing through May 2009. Carrying costs on the deferred balance would have been adjusted to BGE's actual short-term borrowing rate.

Based on the process for approving the rate increases, the April 28, 2006, plan was successfully challenged through litigation in the Circuit Court of Baltimore City. As a result, the March 6, 2006, plan remained in place until the Special Session of 2006 was convened in June 2006. See **Appendix 6** for a comparison of the various proposed plans.

Rate mitigation plans for the PEPCO and Delmarva service territories were negotiated in conjunction with the legislative plans for BGE that were pending on the last day of the 2006 regular session in House Bill 1525 and House Bill 1712 of 2006 (both failed), and were subsequently formally approved by PSC order as modifications of the earlier PSC-approved plan.

Reform Electric Restructuring Legislation: 2006 Special Session

After the failure of legislative rate stabilization plans at the end of the 2006 regular session, the implementation of the Governor's plan, and the outcome of the litigation challenging that plan and its approval by PSC, the General Assembly reconvened in special session on June 14, 2006, to consider comprehensive legislation to address electric industry restructuring, SOS, rate stabilization plans, and the makeup of PSC.

The General Assembly passed Senate Bill 1 (Chapter 5 of 2006) "Public Service Commission – Electric Industry Restructuring." See **Appendix 7** for a summary of the legislation. Governor Robert Ehrlich vetoed the resulting legislation on June 22, 2006; however, the General Assembly overrode the veto on June 23, 2006, enacting the comprehensive energy legislation as Chapter 5 of the Special Session of 2006.

Chapter 5 indefinitely continues the obligation of each local electric utility to provide SOS but alters the procurement of electricity for that service in order to limit price volatility and protect residential and small commercial customers. The procurement of supply for SOS must (1) include a blended portfolio of short-, medium-, and long-term contracts to address different portions of customer load; (2) include cost-effective, energy-efficiency, and conservation measures; and (3) disclose successful bidders.

In the case of a significant increase in the retail cost of electricity for SOS between July 2006 and May 2007, Chapter 5 set a process to defer a portion of the increase with the deferred amount to be repaid in accordance with PSC proceedings. The deferral may be secured by bonds issued on behalf of the electric company and repaid in accordance with a qualified rate order. As discussed below, this process affects residential customers in the BGE service territory.

PEPCO and Delmarva residential customers were offered the opportunity to defer a portion of costs imposed at the same time, without securing the deferred portion of the electric supply cost. The PSC order, as modified by Chapter 5, allowed customers to choose to participate in deferral. Participating customers pay back the deferred expenses over 18 months, but the electric company is required to cover financing charges. Although the initial enrollment period for the PEPCO/Delmarva deferral period expired before the 2006 Special Session occurred and before most customers had seen the magnitude of their new electricity charges, Chapter 5 required these companies to reopen the enrollment period for these customers for an additional period after July 1, 2006.

For all service territories, the changes to the SOS procurement process in Chapter 5 were designed to provide both flexibility and stability for residential customer rates. Although these changes could not by themselves alter the significant increases in cost for electricity that had already been procured by BGE, Delmarva, and PEPCO for their SOS customers through May 31, 2007, the legislature intended to provide more predictable and affordable rates for these customers in the years thereafter, and to avoid precipitous increases in the Allegheny service territory once caps there expire at the end of 2008.

By continuing the obligation to provide SOS indefinitely, the Act was intended to eliminate a four-year "planning window" that was an unintended consequence of the four-year extension of the obligation to serve under the former law. The ability to delay a scheduled bidding cycle, and to reject bids, was intended to provide additional protection to consumers from too rigid a reliance on free-market processes in the wake of natural disasters such as Hurricanes Katrina and Rita, which disrupted natural gas markets in advance of the latest electricity bidding cycle. Blending of SOS supply contracts of varying length for investor-owned utilities, and the opportunity to place a portion of SOS load in bilateral contracts, was intended to smooth fluctuations in consumer pricing similar to what electric cooperatives have been doing for some time. Inclusion of cost-effective energy-efficiency measures was intended to restore energy conservation as a valid means of addressing increasing generation needs. The requirement to disclose successful bidders for SOS supply was intended to provide transparency and a degree of confidence for consumers that inappropriate market manipulation could not occur.

Chapter 5 expanded the pool of applicants eligible for the Electric Universal Service Program and increased the total amount of funds collected for this fund each year to $37 million, with the industrial and commercial classes paying the additional amount. Lastly, the legislation altered the term of the PSC commissioners effective June 30, 2006. *(Note: The Court of Appeals ruled in September 2006 that the termination of incumbent commissioners is an unconstitutional usurpation of the removal power granted to the Governor.)*

BGE Mitigated Rate Increases in the Reform Legislation

For the BGE service territory, Chapter 5 mandated a 15 percent cap on the rate increase on the total electric bill for residential customers. The Act requires BGE to defer collection of the difference between the capped rate and the full 72 percent rate for 11 months. BGE must finance that deferral by creating a security interest, in the amount of the deferred collections, and sell bonds with a term of 10 years and interest sufficient to sell the bonds. The difference is a credit applied to the distribution portion of the bill; the amount of the credit is 4.577 cents per kWh for June through September 2006 and 5.052 cents per kWh for October 2006 through May 2007. The deferral and financing charge, paid through a monthly charge for 10 years starting January 2008, is expected to cost the average customer (1,000 kWh per month) approximately $5.02 each month. The mandatory nature of the deferral was required to provide a sufficient value of security to make the rate stabilization bonds saleable on the financial markets, and to protect more vulnerable customers from still higher finance costs that would have resulted from an opt-in or opt-out deferral plan.

The interest and part of the principal, however, are offset by credits provided by BGE ($2.83 each month for the average customer) based on the SOS authorized return and the nuclear decommissioning charge and so that the cost to the average customer who remains on SOS is approximately $2.19 each month. In total, approximately $386 million in credits are required unconditionally as follows:

- $200 million over 10 years in credits for BGE to forego profits it would have begun collecting from residential customers on July 1, 2006, for providing SOS service; and

- $186 million over 10 years in credits in decommissioning costs BGE has been collecting from residential customers for the Calvert Cliffs nuclear plants.

The legislation contemplated an additional $214 million, depending on whether the merger of Constellation Energy and Florida Power and Light was approved (as savings that BGE would have realized from merger-related efficiencies). *(Note: The proposed merger filing was terminated in October 2006 and, therefore, these additional credits will not be realized.)*

All customers receive the monthly deferral credits and the monthly deferral charge whether or not an alternative supplier is selected. Because the legislation requires BGE to show the adjustments for the 15 percent cap, the SOS return credit, the nuclear decommissioning credit, and any merger savings as credits on the distribution of electricity rather than on generation, all residential customers have the opportunity to save additional money by shopping for alternative electricity supply.

New Developments in Competition Following 2006 Legislation

Although a truly competitive market has not developed, as of July 2006, BGE customers have at least eight plan alternatives to SOS, offered by five suppliers. The rate indicated in **Exhibit 2** is in addition to BGE's distribution rate of approximately $.03 per kWh. While most plans offer flat rates, several plans offer a variable rate where there is no protection from month-to-month increases if the price of wholesale power increases. Depending on the plan, estimated monthly savings range from $12 to $20 per month during summer months and from $1 to $6 per month during nonsummer months.

Exhibit 2
Alternatives to BGE's SOS
July 2006

Supplier	Rates	Estimated Monthly Savings	Early Cancellation Fee
Washington Gas Energy Services	Through June 2007 Summer: 10.72 cents/kWh Nonsummer: 10.21 cents/kWh	Summer: $12 Nonsummer: $3	$75 or $50
Commerce Energy	12-month contract Summer and nonsummer: 10.4 cents/kWh	Summer: $15 Nonsummer: $1	$75
Commerce Energy	Variable rate (no length contract requirement) Starting 10.1 cents/kWh; changes with the market	Summer: $18 initially Nonsummer: less savings than in the summer	None
Ohms Energy	4-month contract Summer and nonsummer: 9.91 cents/kWh	Summer: $20 Nonsummer: $6	$75
Ohms Energy	10-month contract Summer and nonsummer: 10.10 cents/kWh	Summer: $18 Nonsummer: $4	$75
Pepco Energy Services	Variable rate and 12-month contract Summer: 10.36 cents/kWh Nonsummer: 10.21 cents/kWh Note: 10% of product is "green"	Summer: $15 initially Nonsummer : $2 initially No protection if price of wholesale power increases	$75
Maryland Energy Consortium	4-month contract Summer and nonsummer: 10.04 cents/kWh	Summer: $18 Nonsummer: $5	None
Maryland Energy Consortium	10-month contract Summer and nonsummer: 10.31 cents/kWh	Summer: $16 Nonsummer: $2	None

As a result of the entrance of alternative suppliers, almost 11,100 residential customers (1 percent of total customers) in the BGE service territory, almost 26,000 residential customers (5.5 percent of total customers) in the PEPCO service territory, and slightly more than 300 residential customers (0.2 percent) in the Delmarva service territory had switched from SOS by the end of September 2006.

Outlook for Electricity Needs Beginning June 1, 2007

Chapter 5 mandates several reports to assist the General Assembly in assessing the impact of electric restructuring on the State and in altering it for the benefit of consumers. PSC must study actions taken to implement restructuring and must study the impact of potential changes such as re-regulating electric generation or allowing local aggregation. Further, PSC must study and evaluate the procurement and terms and conditions of SOS for residential and small commercial customers. In addition to the evaluation of the full requirements bid process, PSC must consider other changes to the wholesale procurement process such as allowing utilities to meet their SOS obligations through bilateral contracts; adopting a portfolio of blended wholesale supply contracts of short, medium, or long terms; and owning or leasing generation. These elements may be incorporated in to the bidding process as the result of an in-depth investigation. The commission is currently reviewing changes specified in two cases entitled "Competitive Selection of Electricity Supplier/Standard Offer or Default Service" and "Optimal Structure of the Electric Industry in Maryland." *(Note: In a recent order, dated November 8, 2006, PSC altered the bidding process for residential SOS to include two bidding cycles each year rather than the single cycle used in 2004 through 2006, as well as making several other significant changes to the SOS procurement process.)*

Chapter 5 also requires the State Department of Assessments and Taxation to study whether the current valuation of power plants provides an adequate and equitable determination of the value of power plants in a restructured electric industry.

The U.S. Energy Department reported in October 2006 that the outlook in natural gas prices forecasts a decline in natural gas prices. The cause of the decline is due to a mild 2006 winter, followed by moderate 2006 summer high temperatures, a relatively calm Atlantic hurricane season, and restored output in the Gulf of Mexico. With supplies rebounding to adequate levels, natural gas future prices dipped to $4 per BTU in September 2006. The last time natural gas futures settled below $5 was September 2004.

Since the wholesale electricity market is heavily influenced by movements in the natural gas market, when local electric companies go to the SOS auction to secure their power load effective June 1, 2007, lower electric prices are anticipated. Cheaper prices may provide competing power suppliers an opportunity to lock in costs lower than the local electric company.

As discussed above, all rate cap restrictions have now expired for residential, commercial, and industrial customers except for Allegheny Power's residential SOS customers;

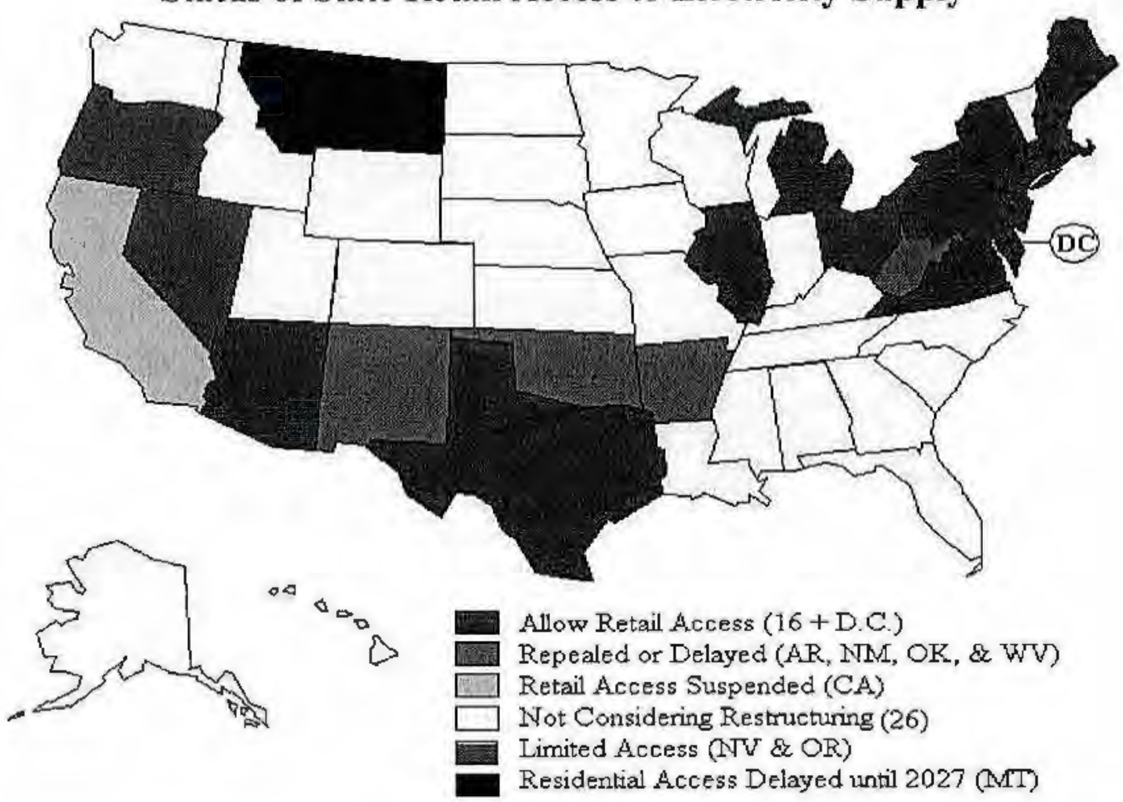
their rates are frozen (after a 7 percent reduction in 2000) until December 31, 2008. The price for unfilled power load secured in the 2007 bidding process will blend with the prices for the contracts which are currently in place (most of which are at the high rates secured in the 2006 bidding process). The percentages of residential and small commercial load that are unfilled as of June 1, 2007 are as follows:

BGE: 50 percent of residential load; 63 percent of Type I load
PEPCO: 79 percent of residential load; 66.7 percent of Type I load
Delmarva: 80.5 percent of residential load; and 66.1 percent of Type I load

Overview of the National Status of Electricity Restructuring
Part 2

The national status of retail access to electricity supply has been relatively unchanged for several years. At this time, 16 states and the District of Columbia have fully implemented legislation and commission orders to allow full retail access for all consumer groups. Thirty-four states are not considering restructuring or have repealed, delayed, limited, or suspended their efforts.[1] The status of electricity market restructuring is shown in **Exhibit 3**.

Exhibit 3
Status of State Retail Access to Electricity Supply



Source: U.S. Department of Energy/Energy Information Administration

[1]Kenneth Rose and Karl Meeusen, 2006 Performance Review of Electric Power Markets: Review Conducted for the Virginia State Corporation Commission 2 (2006).

Two states, Nevada and Oregon, allow retail access to electricity supply for large consumers only. Six states that adopted restructuring later delayed or repealed their plans: Oklahoma and West Virginia passed restructuring legislation but have not gone forward with restructuring plans; Arkansas and New Mexico repealed their laws; Montana has delayed full implementation of its restructuring plan until 2027; and California suspended its restructuring plan in 2001 after experiencing a power crisis.

No states have opted to restructure their retail electricity supply markets since 2000, when the California power crisis began. The remaining 26 states did not adopt electric restructuring legislation or a commission plan and are not considering it at this time. Many of these states actually were considering restructuring; however, these states either slowed their efforts to wait for the outcome of the situation in the West or they stopped any activity altogether.

In addition to the California power crisis, the electricity supply industry has been plagued by other problems that will likely further discourage electricity market restructuring. Some of these problems include the Enron scandal, revelations of market price manipulation, disclosures of accounting improprieties, and the Northeast blackout of 2003.[2]

National Electricity Rates

Between 2002 and 2005, the national average residential retail price of electricity rose 11.35 percent. For the same time period, the states that have maintained a regulated electricity supply market saw average prices that increased at a rate nearly identical to the national average, approximately 11.30 percent. In the five restructured jurisdictions whose transition period to a market structure had ended by 2005, residential prices generally increased faster than the national average: New Jersey's and the District of Columbia's average rates rose by about 13.2 percent; New York's average rate rose by nearly 16 percent; Massachusetts saw an increase of over 23 percent. Maine, however, saw an increase of only 3.06 percent. However, numerous states that did not restructure experienced rate increases over the national average: Alabama, Colorado, Florida, Georgia, Hawaii, Iowa, Kentucky, Louisiana, Mississippi, South Carolina, Utah, and Wisconsin saw rate increases that ranged from 11.78 percent in Utah to 32.18 percent in Hawaii. In addition, Montana and Oklahoma, states that delayed their restructuring plans, saw increases of 12.03 percent and 19.91 percent, respectively. From 2002 to 2005, Maryland's average residential electricity rates rose below the national average, at 6.33 percent. Each state's average price of electricity for residential customers for calendar 2002-2005 is shown in **Exhibit 4**.

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[2] *Id.* at 13.

Exhibit 4
Average Retail Price of Electricity to Residential Customers
Calendar 2002-2005

State	2002	2003	2004	2005	Percent Change 2002-2005	State Restructured
	(Cents per Kilowatt hour)					
Alabama	7.12	7.39	7.62	8.06	13.20%	No
Alaska	12.05	11.98	12.44	13.23	9.79%	No
Arizona	8.27	8.35	8.46	8.88	7.38%	Yes
Arkansas	7.25	7.24	7.36	7.96	9.79%	Repealed
California	12.96	12.00	12.51	12.00	-7.41%	Suspended
Colorado	7.37	8.14	8.42	9.06	22.93%	No
Connecticut	10.96	11.31	11.63	13.63	24.36%	Yes
Delaware	8.70	8.59	8.78	9.02	3.68%	Yes
Dist. of Columbia*	7.98	7.84	8.00	9.03	13.16%	Yes
Florida	8.16	8.55	8.99	9.62	17.89%	No
Georgia	7.63	7.70	7.86	8.72	14.29%	No
Hawaii	15.63	16.73	18.06	20.66	32.18%	No
Idaho	6.59	6.24	6.10	6.28	-4.70%	No
Illinois	8.39	8.38	8.37	8.34	-0.60%	Yes
Indiana	6.91	7.04	7.30	7.49	8.39%	No
Iowa	8.35	8.57	8.96	9.36	12.10%	No
Kansas	7.67	7.71	7.74	7.97	3.91%	No
Kentucky	5.65	5.81	6.11	6.41	13.45%	No
Louisiana	7.10	7.84	8.05	9.01	26.90%	No
Maine*	12.74	12.73	12.16	13.13	3.06%	Yes
Maryland	**7.74**	**7.73**	**7.80**	**8.23**	**6.33%**	**Yes**
Massachusetts*	10.93	11.60	11.75	13.46	23.15%	Yes
Michigan	8.28	8.35	8.33	8.60	3.86%	Yes
Minnesota	7.49	7.65	7.92	8.34	11.35%	No
Mississippi	7.28	7.60	8.21	8.80	20.88%	No
Missouri	7.06	6.96	6.97	7.08	0.28%	No
Montana	7.23	7.56	7.86	8.10	12.03%	Delayed
Nebraska	6.73	6.87	6.96	7.10	5.50%	No
Nevada	9.43	9.02	9.69	10.19	8.06%	Limited Access
New Hampshire	11.89	11.98	12.49	13.55	13.96%	Yes
New Jersey*	10.38	10.67	11.23	11.75	13.20%	Yes

State	2002	2003	2004	2005	Percent Change 2002-2005	State Restructured
	(Cents per Kilowatt hour)					
New Mexico	8.50	8.69	8.67	9.16	7.76%	Repealed
New York*	13.55	14.31	14.54	15.71	15.94%	Yes
North Carolina	8.19	8.32	8.45	8.77	7.08%	No
North Dakota	6.39	6.49	6.79	7.00	9.55%	No
Ohio	8.24	8.26	8.45	8.50	3.16%	Yes
Oklahoma	6.73	7.47	7.72	8.07	19.91%	Delayed
Oregon	7.12	7.06	7.18	7.25	1.83%	Limited Access
Pennsylvania	9.74	9.59	9.58	9.92	1.85%	Yes
Rhode Island	10.20	11.61	12.19	12.92	26.67%	Yes
South Carolina	7.72	8.01	8.12	8.72	12.95%	No
South Dakota	7.40	7.47	7.65	7.77	5.00%	No
Tennessee	6.41	6.55	6.90	7.00	9.20%	No
Texas	8.05	9.16	9.73	10.84	34.66%	Yes
Utah	6.79	6.90	7.21	7.59	11.78%	No
Vermont	12.78	12.82	12.94	13.06	2.19%	No
Virginia	7.79	7.76	7.99	8.14	4.49%	Yes
Washington	6.29	6.31	6.37	6.54	3.97%	No
West Virginia	6.23	6.24	6.23	6.21	-0.32%	Delayed
Wisconsin	8.18	8.67	9.07	9.64	17.85%	No
Wyoming	6.97	7.04	7.21	7.37	5.74%	No
U.S. Total	**8.46**	**8.70**	**8.97**	**9.42**	**11.35%**	

*In these jurisdictions the transition to restructuring was completed by 2005.

Source: U.S. Department of Energy/Energy Information Administration

An analysis of more recent changes in residential electricity rates shows an interesting trend. As shown in **Exhibit 5**, from the months of January through July of 2005 to January through July of 2006, the national average residential retail price of electricity rose 11.83 percent, only slightly higher than the rise the nation had seen from 2002 to 2005. For the same time period, 8 of the 16 states with a restructured electricity supply market saw increases that were above the national average. For example, Connecticut experienced an average increase of 21.54 percent; Delaware saw increases of 19.95 percent; Rhode Island experienced an average increase of 24.43 percent; and Texas saw increases of 21.55 percent. However, four states that did not restructure also experienced rate increases above the national average: Alaska's rates rose an average of 13.50 percent; Florida's rates rose 18.09 percent; Hawaii's rates rose an average of 19.90 percent; and Mississippi's rates rose an average of 15.83 percent. California, the only state that has suspended restructuring, experienced an average increase of 19.97 percent. From July 2005 to July 2006, Maryland's rates rose 10.70 percent, less than the national average. Each state's average price of electricity for residential customers for the year-to-date from July 2005 to July 2006 is shown in Exhibit 5.

Exhibit 5

Average Retail Price of Electricity to Residential Customers

Year-to-date July 2005 and July 2006

	(Cents per Kilowatt hour)		**Percent Change**	
State	**July 2005**	**July 2006**	**July 2005 to July 2006**	**State Restructured?**
Alabama	7.85	8.7	10.83%	No
Alaska	12.89	14.63	13.50%	No
Arizona	8.85	9.28	4.86%	Yes
Arkansas	7.6	8.31	9.34%	Repealed
California	11.97	14.36	19.97%	Suspended
Colorado	8.89	9.12	2.59%	No
Connecticut	13.37	16.25	21.54%	Yes
Delaware	8.72	10.46	19.95%	Yes
Dist. of Columbia*	8.69	9.52	9.55%	Yes
Florida	9.51	11.23	18.09%	No
Georgia	8.43	9.06	7.47%	No
Hawaii	19.5	23.38	19.90%	No
Idaho	6.18	6.23	0.81%	No
Illinois	8.32	8.51	2.28%	Yes
Indiana	7.36	8.2	11.41%	No
Iowa	9.28	9.68	4.31%	No
Kansas	7.79	8.25	5.91%	No
Kentucky	6.31	6.86	8.72%	No
Louisiana	8.38	9.03	7.76%	No
Maine *	13.18	14.75	11.91%	Yes
Maryland	**8.13**	**9**	**10.70%**	Yes
Massachusetts*	13.13	17.22	31.15%	Yes
Michigan	8.6	9.95	15.70%	Yes

State	July 2005 (Cents per Kilowatt hour)	July 2006	Percent Change July 2005 to July 2006	State Restructured?
Minnesota	8.23	8.72	5.95%	No
Mississippi	8.4	9.73	15.83%	No
Missouri	7.1	7.48	5.35%	No
Montana	7.94	8.14	2.52%	Delayed
Nebraska	6.92	7.25	4.77%	No
Nevada	10.07	10.98	9.04%	Limited Access
New Hampshire	13.09	14.99	14.51%	Yes
New Jersey*	11.41	12.52	9.73%	Yes
New Mexico	8.95	9.08	1.45%	Repealed
New York*	14.88	16.51	10.95%	Yes
North Carolina	8.59	9.08	5.70%	No
North Dakota	6.75	7	3.70%	No
Ohio	8.42	9.36	11.16%	Yes
Oklahoma	7.65	8.55	11.76%	Delayed
Oregon	7.21	7.43	3.05%	Limited Access
Pennsylvania	9.79	10.41	6.33%	Yes
Rhode Island	12.28	15.28	24.43%	Yes
South Carolina	8.57	9.01	5.13%	No
South Dakota	7.66	7.84	2.35%	No
Tennessee	6.9	7.69	11.45%	No
Texas	10.35	12.58	21.55%	Yes
Utah	7.55	7.68	1.72%	No
Vermont	12.99	13.53	4.16%	No
Virginia	8.09	8.4	3.83%	Yes
Washington	6.49	6.69	3.08%	No
West Virginia	6.2	6.24	0.65%	Delayed
Wisconsin	9.49	10.34	8.96%	No
Wyoming	7.28	7.53	3.43%	No
U.S. Total	**9.21**	**10.3**	**11.83%**	

*In these jurisdictions, the transition to restructuring was completed by 2005.

Source: U.S. Department of Energy/Energy Information Administration

A regional analysis of electricity price increases for the year-to-date from July 2005 to July 2006 also presents interesting data. During this one-year period, the New England census division saw average residential rates increase at a rate of 23.36 percent, nearly double the national average. The Mountain census division saw the smallest increases, with an average of only 4.20 percent. The West South Central, Pacific Contiguous, and Pacific Noncontiguous census divisions all experienced average residential electricity price increases above the national average. The Middle Atlantic, East North Central, West North Central, South Atlantic, and East South Central divisions experienced price increases below the national average. The U.S. Census Bureau includes Maryland in the South Atlantic census division. Each census division's average price of electricity for residential customers for the year-to-date from July 2005 to July 2006 is shown in **Exhibit 6.**

Exhibit 6

Average Retail Price of Electricity to Residential Customers

Year-to-date July 2005 and July 2006

	(Cents per Kilowatt hour)		**Percent Change**
Census Division	**July 2005**	**July 2006**	**July 2005 to July 2006**
New England	13.14	16.21	23.36%
Middle Atlantic	12.03	13.14	9.23%
East North Central	8.37	9.17	9.56%
West North Central	7.73	8.13	5.17%
South Atlantic*	8.68	9.62	10.83%
East South Central	7.24	8.09	11.74%
West South Central	9.52	11.24	18.07%
Mountain	8.58	8.94	4.20%
Pacific Contiguous	9.95	11.48	15.38%
Pacific Noncontiguous	16.87	19.83	17.55%
U.S. Total	**9.21**	**10.3**	**11.83%**

*Includes Maryland.

Source: U.S. Department of Energy/Energy Information Administration

Comparison of Restructured States' Rates with Nonrestructured States' Rates

As shown in **Exhibit 7**, from 2002 to 2005, the average residential price increase for states that did not restructure was 11.30 percent, nearly identical to the national average residential price increase of 11.35 percent. For the same time period, the average residential price increase for all states that restructured was 12.10 percent, higher than the national average. Of note, in the five restructured jurisdictions whose transition period to a market structure had ended by 2005, residential prices increased by 13.45 percent.

Exhibit 7
Percent Increase in Average Residential Retail Price
Calendar 2002-2005

	2002 Average Cents per kWh	2005 Average Cents per kWh	Percent Increase 2002-2005
Nonrestructured States	7.83	8.71	11.30%
Restructured States	9.64	10.80	12.10%
States with Completed Transition by 2005*	11.12	12.62	13.45%
U.S. Total	**8.46**	**9.42**	**11.35%**

*Data for these states (District of Columbia, Maine, Massachusetts, New Jersey, and New York) is incorporated into data for restructured states.

Source: U.S. Department of Energy/Energy Information Administration

As shown in **Exhibit 8,** from July 2005 to July 2006 the average residential price increase for states that have not restructured was 7.75 percent, which was below the national average of 11.83 percent. For the same time period, the average residential price increase for all of the states that have restructured was 14.33 percent, higher than the national average price increase and higher than the increase for nonrestructured states. For the five jurisdictions that had completed transition to a restructured market by 2005, the average residential price increase was over 15.00 percent.

Exhibit 8
Percent Increase in Average Residential Retail Price
Year-to-date July 2005 to July 2006

	July 2005 Average Cents per kWh	July 2006 Average Cents per kWh	Percent Increase, July 2005 to July 2006
Nonrestructured States	8.51	9.17	7.75%
Restructured States	10.55	12.06	14.33%
States with Completed Transition by 2005*	12.26	14.10	15.06%
U.S. Total	**9.21**	**10.30**	**11.83%**

*Data for these states (District of Columbia, Maine, Massachusetts, New Jersey, and New York) is incorporated into data for restructured states.

Source: U.S. Department of Energy/Energy Information Administration

Comparison of Residential Electricity Prices – Selected Utilities in Selected States

A comparative analysis of electricity rates paid by customers of Baltimore Gas and Electricity (BGE) with customers in other states is a difficult and complicated undertaking. Because each electric utility faces unique factors that drive the retail price of electricity, a complete analysis across various states would be long and complex. Therefore, in the interest of brevity, this section examines the prices for electricity paid by residential customers of Maryland's largest utility (BGE, serving 1.1 million residential customers) compared to customers served by the largest electricity utility in each of six nearby states. In the Northeast, two companies are examined: New York's Consolidated Edison (ConEd), serving 3.4 million customers; and Central Vermont Public Service (CVPS), serving 151,000 customers. Two companies are examined in the Mid-Atlantic region: Delmarva Power of Delaware (Delmarva), serving 500,000 customers; and Allegheny Energy of West Virginia (Allegheny) serving approximately 1.5 million customers. Delmarva and Allegheny also serve customers in Maryland, but for this report only their rates in Delaware and West Virginia are examined. Two companies are examined in the South: Dominion Virginia Power (Dominion), which serves approximately 2 million customers; and North Carolina's Duke Energy (Duke), which serves over 3 million customers in five states.

This report considers only basic residential rate schedules; residential time-of-use schedules and other residential rates are not taken into account for brevity and ease of use. Each scenario discussed below is based on an average residential electricity customer who uses an average of 1,000 kilowatt hours (kWh) of electricity each month, or 12,000 kWh each year.

Factors Impacting Electricity Prices

An analysis that compares only average residential prices is incomplete. When comparing the retail price of electricity across markets, one must also consider the factors contributing to the end-use cost. Electricity generation, wholesale purchasing, and transmission are complex systems that contribute to electricity price fluctuations. Aside from the systematic components, the major factors that determine the retail price of electricity are the cost and availability of fuel used for power generation; the construction costs of generation plants and the associated expenses for operation and maintenance; supply and demand for fuel and transmission; international events; and weather changes.

Natural gas prices are often cited as one of the leading factors impacting retail electricity prices, particularly in states that have restructured their electric supply markets. For example, in the PJM Interconnection, the grid operator accepts bids from electricity generators to fill the expected demand for the following day. The grid operator accepts the lowest bids first, which typically come from low-priced nuclear and coal generators. However, during peak consumption hours, especially during periods of warm weather, the demand for electricity may increase to a point where generating units that normally do not run are called into service. These units often use natural gas. For these periods, PJM will accept higher bids from those higher-priced generating units. The last bid of the day, usually the highest bid, is the price that is paid to all power producers. Therefore, price increases for electricity generally correlate with increasing natural gas prices.

For purposes of this report, it is not feasible to consider all of the factors above when comparing the rates Maryland residential customers pay to the rates residential customers pay in other states. Thus, for each state examined below, this section presents only some of the major factors that contribute to electricity prices (*i.e.*, major fuel components, the method of wholesale electricity purchasing (where applicable), whether the utility under consideration has sold off its generating facilities, and whether the utility has had its rates reduced or frozen). This section briefly examines these and other major factors and their impact on the price of electricity in the respective states.

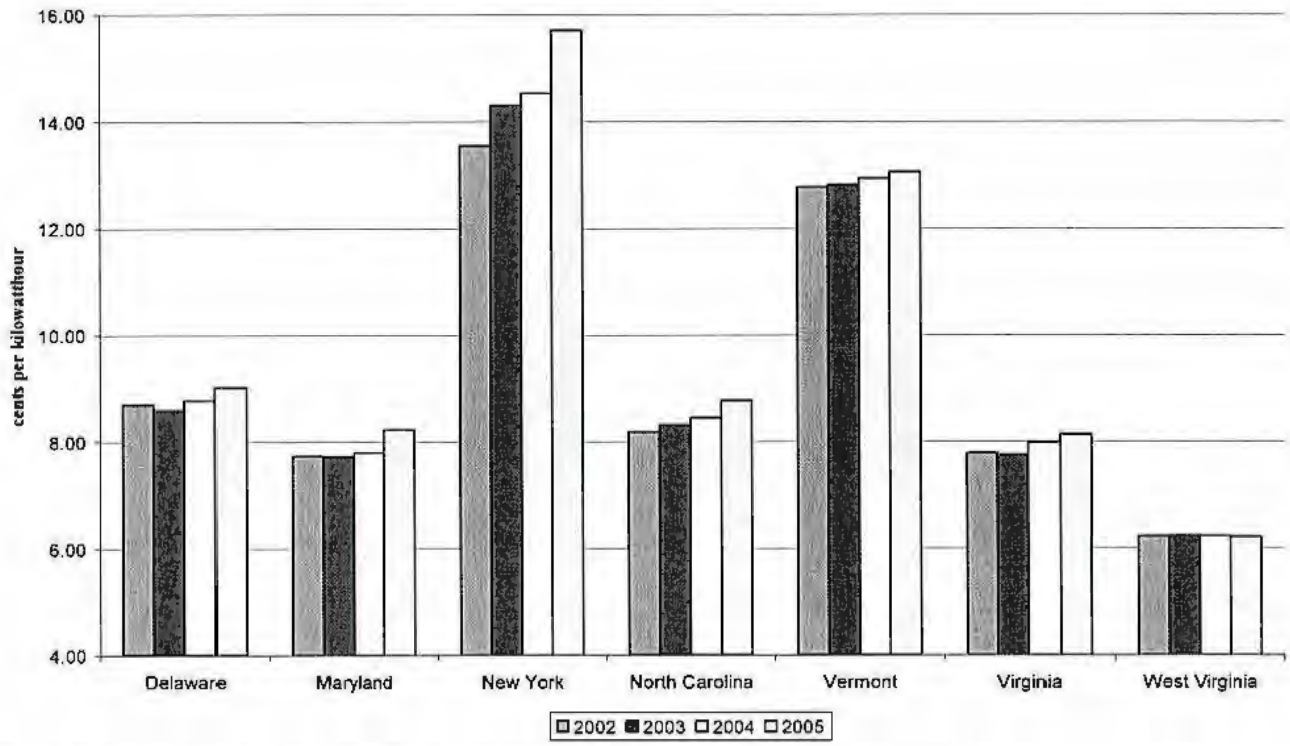
Overview of Residential Electricity Rates in Selected States

As discussed in the national overview above, for the four-year period from 2002 to 2005, the U.S. average residential price for electricity increased by 11.35 percent. For the same time period, the states that are considered in this section generally experienced increases less than the national average; West Virginia actually experienced a slight decrease of less than one-half of one percent. New York's increases were greater than the national average, at 16 percent. For Maryland, Delaware, and Virginia, in 2005 most of the residential electricity prices were still controlled through rate caps during the transition to retail access to electricity supply. The average residential price increases for these states were 6.33 percent, 3.68 percent, and

4.49 percent, respectively. During this time period, New York and Vermont generally had prices well above Maryland's. West Virginia had prices below Maryland's. **Exhibit 9** shows a visual presentation of the average residential electricity prices for each state considered in this report.

Exhibit 9

Average Residential Retail Price, 2002-2005

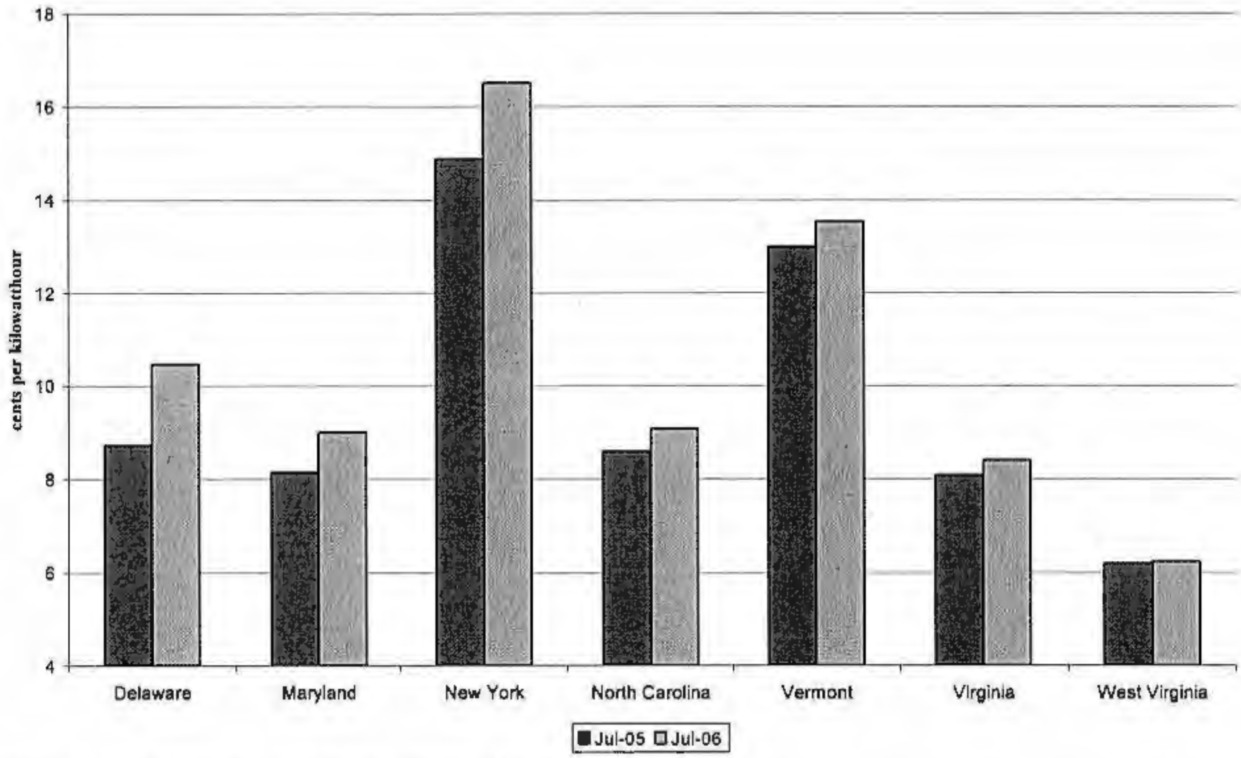


Source: U.S. Department of Energy/Energy Information Administration

For the period from July 2005 to July 2006, the U.S. average residential price for electricity increased by 11.83 percent. For the same time period, with the exception of Delaware, the states that are considered in this section experienced increases less than the national average. Delaware had increases that were greater than the national average, at nearly 20.00 percent. For Maryland and New York, increases were below 11.00 percent. North Carolina's increase was 5.70 percent, while Vermont and Virginia experienced increases of 4.16 and 3.83 percent, respectively. West Virginia's increase from July 2005 to July 2006 was the smallest in the nation at just over one-half of one percent. A visual presentation of the average residential retail price increase from July 2005 to July 2006 can be seen in **Exhibit 10**.

Exhibit 10

Average Residential Retail Price, July 2005 and July 2006



Source: U.S. Department of Energy/Energy Information Administration

As of July 2006, Maryland ranks thirtieth nationally in terms of the average retail price residential customers pay for electricity. The other states considered in this section rank as follows: Delaware ranks fifteenth; New York has the third highest average residential rates nationally; North Carolina ranks twenty-sixth; Vermont tenth; Virginia thirty-fourth; and West Virginia fiftieth, with rates higher than only Idaho.

Electricity Rates in Maryland – Baltimore Gas and Electricity

The chart below sets out the monthly, seasonal, and annual price a residential customer of BGE might pay for electricity service, excluding taxes. A BGE customer who uses 1,000 kWh of electricity per month might expect to pay approximately $1,162.11 over the course of one year for BGE's SOS product (July 1, 2006 to June 30, 2007). When taxes are factored in, this amount will be higher. As of July 2006, Maryland ranks thirtieth in the nation in the average residential price for electricity.

Electricity Rates for BGE – Maryland

Rates are kWh basis unless noted

	Rates Effective 5/31/2006		Rates x 1,000 kWh	
Residential Rates - Schedule R (Excludes All Taxes)	**Summer** June - Sept.	**Winter** Oct. - May	**Summer** June - Sept.	**Winter** Oct. - May
Distribution				
Customer (per bill)	$ 7.50	$ 7.50	$ 7.50	$ 7.50
Energy	$ 0.02370	$ 0.02370	$23.70000	$23.70000
Transmission				
Transmission Rate	$ 0.00315	$ 0.00315	$3.15000	$3.15000
Generation (SOS)				
Energy**	$ 0.11556	$ 0.10200	$115.56000	$102.00000
Total Cost of Electricity Per Month, Minus Non-by Passable Charges			**$ 149.91**	**$ 136.35**
Total Cost of Electricity for All Summer Months			**$599.64**	
Total Cost of Electricity for All Winter Months				**$1,090.80**
Non-by Passable charges (Approximate)				
Deferred amount 7/1/06 - 5/31/07	$ (0.04577)	$ (0.05052)	($45.77000)	($50.52000)
Deferred payback beginning 1/1/07 for 10 years	$ 0.00502	$ 0.00502	$5.02000	$5.02000
Decommissioning credit beginning 1/1/07 for 10 years	$ (0.00133)	$ (0.00133)	($1.33000)	($1.33000)
SOS profit factor suspended beginning 1/1/07 for 10 years*	$ (0.00150)	$ (0.00150)	($1.50000)	($1.50000)
Total Non-by Passable Charges and Credits for One Year			**(528.33)**	
Total Cost of Electricity for 7/1/06 - 6/30/07, without Non-by Passable Charges and Credits			**$1,690.44**	
Total Cost of Electricity for 7/1/06 - 6/30/07			**$1,162.11**	

*BGE generation includes SOS profit factor beginning July 1, 2006.

**BGE SOS changes with new auctions effective June 1, 2007.

Source: Public Service Commission, Utility web sites (tarriff schedules), BGE Rate Engineering Staff

Because of the regulations set in place to guide Maryland's transition to a restructured electricity market, natural gas plays a prominent role in the price of power. As discussed in more detail above, one provision of the 1999 legislation that restructured Maryland's electricity industry required BGE to transfer ownership of its generating plants to its parent corporation, Constellation Energy Group, Inc. Beginning in December 2005, the regulations required BGE to purchase all of its electricity from wholesale suppliers in an auction overseen by the PJM Interconnection. At the same time that electricity rate caps were expiring, BGE purchased electricity on the wholesale market at a rate that was much higher than expected and that would have resulted in a 72 percent increase in overall residential prices. The rate chart above shows the effects of a temporary 15 percent limit on the increase that began on July 1, 2006, and expires on May 31, 2007. This limit was imposed by Chapter 5 of the Special Session of 2006. Chapter 5 also allows BGE to implement a further limitation to the phase in of rate increases between May 31, 2007 and January 1, 2008, allowing customers to delay payment of the full-market rates for electricity until January 1, 2008. Beginning on January 1, 2007, and continuing for 10 years, BGE will be able to charge a fee to recover the deferred cost of electricity consumed during the switch to market rates.

Although the price for residential electricity service in Maryland has increased, Maryland's rates are still below the median of electricity prices across the nation. As of July 2006, Maryland ranks thirtieth in the nation in terms of average residential electricity rates. Maryland's residential electricity rates are lower than those in other states in the region, such as New Jersey and Pennsylvania. This can be explained in part because of the temporary rate caps imposed on BGE. In addition, BGE and other Maryland electric utilities have access to low-cost fuels generated in the region – namely, coal and nuclear power. Maryland's fuel mixture is 56.1 percent coal and 28 percent nuclear power, with small amounts of petroleum, hydroelectric, and natural gas. It is expected that when BGE's residential customers begin to pay full-market rates for electricity, Maryland's overall average residential price for electricity will increase, bringing Maryland closer in ranking to Pennsylvania and New Jersey, other states that have restructured their electricity markets and where rate caps have begun to expire. Maryland's overall average residential price will likely further increase when residential rate caps expire in the Allegheny service territory at the end of 2008.

Sample Northeastern States – New York and Vermont

Electricity Rates in New York – Consolidated Edison

The chart below sets out the monthly, seasonal, and annual price a residential customer with ConEd might pay for electricity service that "bundles" generation and distribution (similar to SOS for BGE customers), excluding taxes. A ConEd customer who uses 1,000 kWh of electricity each month might expect to pay approximately $2,389.03 over the course of one year. When taxes are factored in, this amount will be higher. As of July 2006, New York ranked third in the nation in terms of the average residential price for electricity.

Electricity Rates for Consolidated Edison – New York

Rates are on a kWh basis unless noted

Residential Rates	Rates Effective May 1, 2005		Rates x 1,000 kWh	
Service Classification No. 1	**Summer**	**Winter**	**Summer**	**Winter**
(Excludes All Taxes)	June - Sept.	Oct. - May	June - Sept.	Oct. - May
Customer Charge				
Non Low-income Customers	$11.04	$11.04	$11.04	$11.04
Low-income Customers	$6.00	$6.00		
Delivery Charges				
first 250 kWh	$0.048070	$0.048070	$12.017500	$12.017500
over 250 kWh	$0.054570	$0.043890	$40.927500	$32.917500
Energy Supply Charges				
Competitive Supply-Related Charge*				
first 250 kWh	$0.001500	$0.001500	$0.375000	$0.375000
over 250 kWh	$0.001500	$0.001500	$1.125000	$1.125000
Competitive Supply Collections-related Surcharge				
first 250 kWh	$0.002200	$0.002200	$0.550000	$0.550000
over 250 kWh	$0.002200	$0.002200	$1.650000	$1.650000
Market Supply Charge, NYC**	$0.133845	$0.143269	$133.845000	$143.269000
Other Charges				
Monthly Adjustment Clause, NYC**	$0.005220	($0.002890)	$5.220000	($2.890000)
System Benefits Charge	$0.002000	$0.002000	$2.000000	$2.000000
Renewable Portfolio Standard Surcharge	$0.000200	$0.000200	$0.200000	$0.200000
Statement of Adjustment Factor **	($0.000240)	($0.007980)	($0.240000)	($7.980000)
Total Cost of Electricity Per Month			**$208.71**	**$194.27**
Total Cost of Electricity for All Summer Months			**$834.84**	
Total Cost of Electricity for All Winter Months				**$1,554.19**
Total Cost of Electricity for One Year			**$2,389.03**	

*Applicable to bundled service (SOS).

**Average monthly charge calculated from charges, Oct. 2005 to Sept. 2006.

Note: The total dollar amounts above have been rounded to the nearest penny.

Source: Consolidated Edison web site (tariff schedules), Electric Rate Design Staff, Consolidated Edison

New York State began investigating the potential for a competitive electric industry in the early 1990s and by 1998 had approved restructuring plans for each electric utility in the state.

Under an agreement approved by the New York State Public Service Commission, ConEd began to purchase electricity on the wholesale market, which is overseen by the New York Independent System Operator. Also under this agreement, all customers were able to choose an alternative electricity supplier by the end of 2001. Under the restructuring plan, ConEd agreed to divest at least one-half of its power generation facilities; in fact, the company sold nearly all of its power plants.

One major factor contributing to the price of electricity in New York is the generation fuel mixture used to produce electricity. Nearly 30 percent of New York's electricity supply is generated by nuclear power, the largest source of generation in the state. Following nuclear power generation, New York gets about 20 percent of its electricity supply from hydroelectric power and about 20 percent from natural gas. Just over 15 percent of New York's electricity supply is generated using petroleum and about 15 percent using coal. Thus overall, New York presents a balanced mixture of generation fuel utilization. However, it is important to note that, while much of New York's electricity comes from lower-cost hydroelectric and nuclear power, a good portion of the supply also comes from higher-priced petroleum and natural gas. Also of note, legacy costs related to construction of nuclear facilities add to the price of nuclear generation.

Recent history concerning New York's electric policy presents some unique factors that affect the price customers currently pay for electricity. For example, in the 1980s, New York utilities were very aggressive in signing up cogeneration contracts pursuant to the Public Utilities Regulatory Policy Act of 1978 (PURPA). ConEd and other electric utilities typically paid very high prices for these contracts. During restructuring, the New York State Public Service Commission settled with ConEd to allow the legacy costs from these contracts to be recouped as stranded costs. These stranded costs were passed on to customers.

In addition, New York historically has aggressively implemented conservation programs that affect the price of electricity. Beginning in the 1970s, New York implemented clean air programs aimed at reducing air pollution.

Electricity Rates in Vermont – Central Vermont Public Service

The chart below sets out the monthly, seasonal, and annual price a residential customer with Central Vermont Public Service (CVPS) might pay for electricity service, excluding taxes. A CVPS customer who uses 1,000 kWh of electricity each month might expect to pay approximately $1,564.61 over the course of one year. When taxes are factored in, this amount will be higher. As of July 2006, Vermont ranked tenth in the nation in terms of the average residential price for electricity.

Electricity Rates for Central Vermont Public Service – Vermont		
Rates are on a kWh basis unless noted		
Residential Rates – Schedule 1	Rates Current as of 09/18/06	Rates x 1,000 kWh
(Excludes All Taxes)	**All Months**	**All Months**
Customer Service Charge (per bill)	.364 per day	$11.284000
Energy Charge	$0.114170	$114.170000
Efficiency Utility Charge	$0.004930	$4.930000
Total Cost of Electricity Per Month		$130.38
Total Cost of Electricity for One Year		**$1,564.61**
Note: The total dollar amounts above have been rounded to the nearest penny.		
Source: Central Vermont Public Service web site (rate schedules), Central Vermont Public Service Rate Design Staff		

Vermont is unusual because it is the only state in New England that has not restructured its electricity supply market. As a vertically integrated utility, CVPS is insulated from some of the factors that lead to large jumps in electricity prices. This can be seen in the company's residential rates for the past five years. There has been relatively little change in the rates, while companies in other states have instituted relatively large increases.

While Vermont's residential electricity rates are below those of other New England states, the state's rates are relatively high when compared to the rest of the United States. Vermont ranks tenth in terms of the average residential price for electricity. On average, residential customers in the state pay 13.53 cents per kilowatt hour.

Approximately 70 percent of CVPS's electricity is generated from nuclear power, and the remainder is mostly hydroelectric. However, like ConEd of New York, CVPS continues to pass the costs of legacy PURPA contracts on to customers. This is one reason electricity rates are surprisingly high in spite of what is expected to be inexpensive nuclear and hydroelectric generation. In addition, much of Vermont's hydroelectric power comes from Canada, which adds to costs. Further, states in the northeast do not enjoy the level of federal funding for hydroelectric power such as can be found in other regions of the nation.

Sample Mid-Atlantic States – Delaware and West Virginia

Electricity Rates in Delaware – Delmarva Power

The chart below sets out the monthly, seasonal, and annual price a residential customer of Delmarva Power might pay for electricity, excluding taxes. A Delmarva Power customer who uses 1,000 kWh of electricity each month might expect to pay approximately $1,330.11 for one year of electricity. The price will increase with the inclusion of taxes. As of July 2006, Delaware ranked fifteenth in the nation in terms of the average residential price for electricity.

It is important to note that the chart below sets out rates paid by customers in Delaware. Delmarva utilizes a separate rate schedule for its Maryland customers.

Electricity Rates for Delmarva Power – Delaware

Rates are on a kWh basis unless noted

Residential Rates – Schedule R (Excludes All Taxes)	Rates Effective July 1, 2006			Rates x 1,000 kWh	
	Summer	**Winter**		**Summer**	**Winter**
	June - Sept.	Oct. - May		June - Sept.	Oct. - May
Delivery Service Charges					
Customer Charge (per bill)	$7.36	$7.36		$7.36	$7.36
Distribution, first 500 kWh	$0.022703	$0.022703		$11.351500	$11.351500
Distribution, over 500 kWh	$0.022703	$0.022703		$11.351500	$11.351500
Environmental Fund	$0.000178	$0.000178		$0.178000	$0.178000
Low-income Fund	$0.000095	$0.000095		$0.095000	$0.095000
Supply Service Charges					
Transmission Rate	$0.003465	$0.003464		$3.465000	$3.464000
Standard Offer Service					
Supply Capacity, Energy, & Ancillary					
first 500 kWh	$0.105016	$0.116809		$52.508000	$58.404500
over 500 kWh	$0.105016	$0.099577		$52.508000	$49.788500
Standard Offer Service Phase-in Credit	5/01/06 - 12/01/06	1/01/07 - 5/31/07	6/01/07 - 12/31/07		
first 500 kWh Rate – Summer	($0.032881)	($0.009971)	$0.000000		
over 500 kWh Rate – Summer	($0.032881)	($0.009971)	$0.000000		
first 500 kWh Rate – Winter	($0.047008)	($0.022158)	($0.004822)		
over 500 kWh Rate – Winter	($0.039677)	($0.017661)	($0.002303)		
Total Cost of Electricity Per Month, without SOS Phase-in Credit				**$138.82**	**$141.99**
Total Cost of Electricity for All Summer Months				**$555.27**	
Total Cost of Electricity for All Winter Months					**$1,135.94**
Total Cost of Electricity for 6/1/06 - 5/31/07, without Phase-in Credits				**$1,691.21**	
Total Phase-in Credits for 6/1/06 - 5/31/07				**($361.10)**	
Total Cost of Electricity for One Year, 6/1/06 - 5/31/07				**$1,330.11**	

Total Supply Service price is the sum of Standard Offer Service, Transmission and Procurement Cost Adjustment.

Note: The above delivery service charges apply when the customer has an electric supplier other than Delmarva Power as its energy provider. The above delivery and SOS with transmission service charges apply when the customer has Delmarva Power as its energy provider. The total dollar amounts above have been rounded to the nearest penny.

Source: Delmarva Power web site (tariff schedules), Delmarva Power Rate Engineering Staff

Delaware's path to restructuring its electricity supply market has closely tracked Maryland's. Like Maryland, the Delaware General Assembly passed restructuring legislation in 1999. Also like Maryland, Delaware imposed rate caps on its public utilities. Delmarva's rates were decreased by 7.5 percent and frozen until May 1, 2006. Like BGE, Delmarva participated in a power auction in December 2005 and January 2006, when natural gas prices were very high. At that time, Delmarva's electricity purchase led to an increase to residential customers of approximately 59 percent. This increase will be phased in over two years so that by June 1, 2007, Delmarva Power's customers will pay the full-market rate for electricity. In another similarity with BGE, in 2008 Delmarva Power will begin charging its customers a monthly fee to cover the amount of money Delmarva had to borrow during the rate phase-in period. This monthly fee will only be charged for 17 months.

The rate chart for Delmarva Power, above, reflects the price a residential customer will pay during the first step in the market rate phase-in period. After May 1, 2006, overall residential rates for Delmarva's Delaware customers rose by about 15 percent. On January 1, 2007, Delmarva's rates increased an additional 25 percent. On June 1, 2007, Delmarva customers will experience a final rate increase, at which time they will be paying full-market rates.

Electricity Rates in West Virginia – Allegheny Power

The chart below sets out the monthly, seasonal, and annual price a residential customer of Allegheny Power might pay for electricity, excluding taxes. An Allegheny Power customer who uses 1,000 kWh of electricity each month might expect to pay approximately $845.52 for one year of electricity. The price will increase with the inclusion of taxes. As of July 2006, West Virginia ranked fiftieth in the nation in terms of the average residential price for electricity, with rates higher than only Idaho.

It is important to note that the chart below sets out rates paid by customers in West Virginia. Allegheny Power utilizes a separate rate schedule for its Maryland customers.

Electricity Rates for Allegheny Power – West Virginia		
Rates are on a kWh basis unless noted		
Residential Rates - Schedule R	Rates Effective April 21, 2006	Rates x 1,000 kWh
(Excludes All Taxes)	**All Months**	**All Months**
Customer Charge (per bill)	$4.00	$4.00
Energy Charge	$0.066090	$66.090000
Temporary Surcharge	$0.000370	$0.370000
Total Cost of Electricity Per Month		**$70.46**
Total Cost of Electricity for One Year		**$845.52**
Note: The total dollar amounts above have been rounded to the nearest penny.		
Source: Allegheny Power web site (tariff schedules), Allegheny Power Rate Engineering Staff		

Though West Virginia has studied the issue of restructuring, and, in fact, the West Virginia Public Service Commission has drafted a restructuring plan, the West Virginia Legislature stopped short of enacting tax law changes necessary for restructuring implementation. This occurred in the wake of the California electricity crisis of 2000. Therefore, Allegheny Power of West Virginia has not been required to purchase its electricity on the wholesale market.

As noted above, West Virginia's residential electricity rates are the second lowest in the country, and this is reflected in the pricing chart above. The most important reason for the low rates is the fact that West Virginia is the nation's second largest producer of coal, behind Wyoming. Ninety-five percent of electricity generated and consumed in West Virginia comes from coal, the least expensive power generation fuel. The rest comes from small amounts of natural gas, hydroelectric power, and petroleum.

Sample Southern States – North Carolina and Virginia

Electricity Rates in North Carolina – Duke Energy

The chart below sets out the monthly, seasonal, and annual price a residential customer of Duke Energy in North Carolina might pay for electricity, excluding taxes. A Duke Energy customer who uses 1,000 kWh of electricity each month might expect to pay approximately $1,003.34 for one year of electricity. The price will increase with the inclusion of taxes. As of July 2006, North Carolina ranks twenty-sixth in terms of the average price residential customers pay for electricity.

Electricity Rates for Duke Energy, North Carolina

Rates are on a kWh basis unless noted

Residential Rates - Schedule RS	Rates Effective July 1, 2006		Rates x 1,000 kWh	
(Excludes All Taxes)	**Summer**	**Winter**	**Summer**	**Winter**
	July - Oct.	Nov. - June	July - Oct.	Nov. - June
Customer Charge (per bill)	$7.87	$7.87	$7.870000	$7.870000
Energy Charge				
1st 350 kWh	$0.070193	$0.070193	$24.567550	$24.567550
351 - 1,300 kWh	$0.079182	$0.078503	$51.468300	$51.026950
over 1,300 kWh	$0.079182	$0.078503		
Total Cost of Electricity Per Month			**$83.91**	**$83.46**
Total Cost of Electricity for All Summer Months			**$335.62**	
Total Cost of Electricity for All Winter Months				**$667.72**
Total Cost of Electricity for One Year			**$1,003.34**	

Note: The total dollar amounts above have been rounded to the nearest penny.

Source: Duke Energy web site (tariff schedules)

On the national spectrum of rates, North Carolina is close to the median with rates similar to Maryland and Virginia. North Carolina has not restructured its electricity supply market. Duke Energy is a vertically integrated utility. Duke Energy officials report that the company generates approximately 95 percent of its own electricity supply. The rest is purchased from independent suppliers.

Compared to electricity rates in the Northeast, North Carolina's rates are relatively low. For Duke Energy in particular, the rates are kept low mainly because of the fuels used to generate electricity: approximately one-half of Duke Energy's supply is generated from nuclear power; the remainder is generated mainly from coal. This fuel mixture is similar to that in the state as a whole (approximately 60 percent of North Carolina's generation fuel is coal; approximately 32 percent is nuclear power; the rest is generated by hydroelectric and natural gas).

Electricity Rates in Virginia – Dominion Virginia Power

The chart below sets out the monthly, seasonal, and annual price a residential customer with Dominion Virginia Power might pay for electricity service, excluding taxes. A Dominion customer who uses 1,000 kWh of electricity each month might expect to pay approximately $1,046.16 over the course of one year. When taxes are factored in, this amount will be higher.

As of July 2006, Virginia ranks thirty-fifth in terms of the average price residential customers pay for electricity.

Electric Rates for Dominion Virginia Power – Virginia

Rates are on a kWh basis unless noted

Residential Rates Schedule 1–	Base Rates Effective January 1, 2004		Rates x 1,000 kWh	
(Excludes All Taxes)	**Summer**	**Winter**	**Summer**	**Winter**
	June - Sept.	Oct. - May	June - Sept.	Oct. - May
Distribution Service Charges				
Basic Customer Charge (per billing month)	$7.00	$7.00	$7.00	$7.00
Distribution kWh Charge				
first 800 kWh	$0.022330	$0.022330	$17.864000	$17.864000
over 800 kWh	$0.012600	$0.012600	$2.52000	$2.520000
			$20.38	$20.38
Electricity Supply Service Charges				
Electricity Supply Supply Charge				
first 800 kWh	$0.040730	$0.040730	$32.584000	$32.584000
over 800 kWh	$0.060510	$0.032050	$12.102000	$6.410000
			$44.69	$38.99
Fuel Charges (Effective 10-08-2004)	$0.018910	$0.018910	$18.910000	$18.910000
Total Cost of Electric Service Per Month			**$90.98**	**$85.28**
Total Cost of Electric Service for All Summer Months			**$363.92**	
Total Cost of Electric Service for All Base Months				**$682.24**
Total Cost of Electric Service for One Year			**$1,046.16**	

Source: Dominion web site (Virginia Bundled tariff schedules), Dominion Rate Engineering Staff

Currently, Virginia ranks slightly below Maryland in terms of average residential electricity rates. This current status is reflected in the pricing analysis for Dominion, which shows that a residential customer using 1,000 kWh of electricity per month pays approximately $100 less than a BGE customer.

While Virginia has adopted a restructuring plan, the transition to market-based electricity rates will not begin until the end of 2010. Rates are capped until then, though Dominion will be able to adjust its rates to reflect changes in generation fuel prices beginning on July 1, 2007. In the meantime, Dominion is participating in a pilot program that allows some of its customers to choose their electricity supplier. As of May 1, 2006, only 1,373 residential customers out of nearly 2 million have chosen an alternative supplier. It is expected that when rate caps expire in 2011, Dominion customers will experience a significant rise in electricity rates.

As part of Virginia's restructuring plan, Dominion was required to sell its generating plants. Dominion established a new affiliate, Dominion Generation, to own and operate all of Dominion's power generation plants.

Virginia is similar to Maryland in terms of the fuels used to generate electricity. Almost one-half of the fuel used in Virginia is coal, while nuclear power constitutes about 36 percent of the generation supply. The remainder is filled by petroleum, hydroelectric, and natural gas.

Exhibit 11 below shows a summary of the monthly, seasonal, and annual price residential customers serviced by the electric utility companies in the states above might pay for electricity service for one year, excluding taxes.

Exhibit 11
Summary of Residential Electricity Prices for One Year
Selected Utilities in Selected States

State	Utility Company	Approximate Average Retail Price of Electricity for One Year
Maryland	BGE	$1,162.11
New York	Consolidated Edison	2,389.03
Vermont	Central Vermont Public Service	1,564.61
Delaware	Delmarva Power	1,330.11
West Virginia	Allegheny Power	845.52
North Carolina	Duke Energy	1,003.34
Virginia	Dominion Virginia Power	1,046.16

Appendices

Appendix 1

Public Service Commission Cases Relating to Electric Restructuring (1994 to 2006)

Case Number/ Filing Date	Description	Order/ Order Date
9074: 8/17/06	In the Matter of the Investigation Required by Section 11, 2006 Maryland Laws, first Special Session, Public Service Commission – Electric Industry Restructuring	None completed 10/1/06: Report on Residential Customer Arrearages, Turnoffs, and Reconnections in Maryland
9073: 8/17/06	In the Matter of the Investigation Required by Section 5, 2006 Maryland Laws, first Special Session, Public Service Commission – Electric Industry Restructuring	None completed
9069: 7/24/06	In the Matter of the Merger of Constellation Energy Group, Inc., the Corporate Parent of Baltimore Gas and Electric Company, and the FPL Group, Inc.	10/25/06: Joint applicants request to withdraw application to merge and request that PSC close case
9066: 5/25/06	In the Matter of the Commission's Inquiry into the Assignment and Exercise of Auction Revenue Rights and Financial Transmission Rights in the Maryland Standard Offer Service Procurement Process	11/8/02: Proposed order by hearing examiner: recommends keeping ARRs and FTRs with suppliers (cost of congestion can be mitigated using these as hedge)

Case Number/ Filing Date	Description	Order/ Order Date
9064: 5/10/06	In the Matter of the Competitive Selection of Electricity Supplier/Standard Offer or Default Service for Investor-owned Utility Small Commercial Customers; and for the Potomac Edison Company D/B/A Allegheny Power's, Delmarva Power and Light Company's, and Potomac Electric Power Company's Residential Customers (Review of Chapter 5 of Special Session 2006)	81102: 11/8/06: Twice yearly SOS bidding for residentials, set small commercial customers as 25 kW and combine with residentials for SOS, move current small commercials above 25 kW to Type II SOS, one- and two-year contracts, allow BGE to generate an administrative time-of-use differential rather than relying on wholesale bids, reject opt-out municipal aggregation, adopt changes to volumetric risk management, defer to the long-term case alternative energy strategies and Allegany transition
9063: 5/10/06	In the Matter of the Optimal Structure of the Electric Industry in Maryland (Review of Chapter 5 of Special Session 2006)	None completed
9058: 3/3/06	In the Matter of the Commission's Investigation into a Residential Electric Rate Stabilization Plan For Potomac Electric Power Company and Delmarva Power and Light Company	80747: 4/21/06: Establish rate mitigation plan 80632: 3/3/06: Initiate proceedings
9056: 2/17/06	In the Matter of the Commission's Investigation into Default Service for Type II Standard Offer Service Customers	81093: 11/2/06: Challenge to quarterly bid procurements – denied 81019: 8/28/06: Authorizes Type II SOS indefinitely, based upon quarterly bid procurements for the next two years after implementation 80608: 2/17/06: Initiate proceedings
9054: 1/30/06	In the Matter of the Merger of Constellation Energy Group, Inc. the Parent Corporation of Baltimore Gas and Electric Company and Florida Power and Light Group, Inc.	80901: 7/10/06: Dismiss case due to the enactment of Chapter 5 of Special Session 2006 – see case 9069

Case Number/ Filing Date	Description	Order/ Order Date
9052: 1/6/06	In the Matter of the Commission's Investigation into a Residential Electric Rate Stabilization and Market Transition Plan for Baltimore Gas and Electric Company	Case suspended as result of Chapter 5 of Special Session 2006 80838: 6/2/06: court says to consider merger implications 80764: 4/28/06: PSC altered implementation of mitigation plan to more gradual (Governor's Plan) 80638: 3/6/06: PSC staff developed a mitigation plan
9037: 5/25/05	In the Matter of Default Service for Type II Standard Offer Service Customers	80858: 6/16/06: postpone 6/19/06 Type II-A bid procurement 80342: 10/12/05: alter Type II into Type II-A and Type II-B 80272: 9/20/05: set Type II SOS
9019: 8/26/04	In the Matter of the Commission's Inquiry into the Implementation of the Renewable Energy Portfolio Standard	None completed
8995: 1/8/04	In the Matter of Potomac Electric Power Company's Class Cost of Service and Revenue Requirements Study for Distribution Service	79242: 7/7/04: no reduction in PEPCO's distribution rates is warranted
8994: 1/8/04	In the Matter of Delmarva Power and Light Company's Class Cost of Service and Revenue Requirements of Study for Distribution Service	79186: 6/15/03: approval of settlement agreement
8987: 11/14/03	In the Matter of the Inquiry into the Provision of Standard Offer Service by Choptank Electric Cooperative, Inc.	79922: 4/25/05: address SOS for Choptank, using full requirements wholesale service through the Old Dominion Electric Cooperative and a modification of its power cost adjustment mechanism (July 1, 2005 – June 30, 2015 period)
8985: 11/14/03	In the Matter of the Inquiry into the Provision of Standard Offer Service by Southern Maryland Electric Cooperative, Inc.	80839: 7/14/06: permit continued use of managed portfolio procurement process 79503: 9/29/04: address SOS for SMECO during January 2005 – May 2008 period, using a managed portfolio procurement process

Case Number/ Filing Date	Description	Order/ Order Date
8936: 9/13/02	In the Matter of the Provision of Standard Offer Service and Default Service in Delmarva Power and Light Company's Electric Service Area	78148: 11/22/02: approve bridge settlement for nonresidential customers
8908: 12/18/01	In the Matter of the Commission's Inquiry into the Competitive Selection of Electricity Suppliers Standard Offer Service	80276: 9/23/05: approve procurement improvements 79489: 9/24/04: change to the full requirements service agreement; reject municipal opt-out aggregation 79452: 9/13/04: allow Chapter 11 bankrupt supplier to participate in SOS if have procedural guarantees 79097: 4/27/04: file of SOS rates to include return components that is not grossed up for taxes 78930: 2/2/04: Mirant application for reconsideration and rehearing denied 78909: 1/9/04: does not adopt supplemental agreement due to accounting-related uncertainties 78710: 9/30/03: Phase II – Framework for Wholesale Competitive Bidding for SOS – approve settlement (establishes procedures for procuring SOS) 78535: 6/26/03 78400: 4/29/03: Phase I – continue obligation of SOS after finding of noncompetitive market – approve settlement (establishes policy framework for wholesale supply procurement) 77806: 5/30/02: discussion on SOS issues
8903: 10/1/01	In the Matter of the Electric Universal Service Program	80111: 7/20/05: reallocation of $750,000 in weatherization to bill payment assistance 78661: 9/16/03: cease appliance replacement
8890: 6/1/01	In the Matter of the Proposed Merger Involving the Potomac Electric Power Company and Delmarva Power and Light Company	80373: 10/28/05: adjust retail transmission/distribution rates based on FERC-approved wholesale transmission rates 77685: 4/11/02: approve merger

Case Number/ Filing Date	Description	Order/ Order Date
8883: 2/23/01	In the Matter of the Business Separation of Constellation Energy Group	78045: 10/3/02: require Constellation to file separation reports
8823: 9/2/99	In the Matter of Choptank Electric Cooperative, Inc.'s Proposed: (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates	77503: 1/11/02: approve settlement agreement, Choptank to file new tariffs 76842: 3/22/01: approve settlement agreement
8817: 5/3/99	In the Matter of the Southern Maryland Electric Cooperative's Proposed: (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates	77001: 6/5/01: approve settlement agreement 76321: 7/20/01: approve settlement agreement, SMECO to file new tariffs
8797: 6/26/98	In the Matter of the Potomac Edison Company's Proposed: (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates	79495: 9/28/04: approve bid evaluation method 77262: 9/26/01: deny Office of People's Counsel's request that PE be ordered to reflect transmission and ancillary services revenues in the Warrior Run Surcharge for the period ending December 31, 2001 76512: 10/20/00: file tariff relating to cogeneration PURPA project surcharge 76231: 6/6/00: PE to file revised compliance filings re: supplier coordination tariff 76209: 5/30/00: deny rehearing application of PE 76025: 3/24/00: specify PE to refund, or collect, its deferred fuel balance 76009: 3/15/00: approve settlement agreement 75851: 12/27/99: approve settlement agreement
8796: 6/26/98	In the Matter of the Potomac Electric Power Company's Proposed: (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates	Divestiture sharing: approve share divestiture proceeds 76472: 9/27/00: deny Panda-Brandywine issue application 76235: 6/8/00: PEPCO to file revised compliance filings re: supplier coordination tariff 76078: 4/30/00: approve settlement agreement 75850: 12/22/99: approve settlement agreement

Case Number/ Filing Date	Description	Order/ Order Date
8795: 6/26/98	In the Matter of the Delmarva Power and Light Company's Proposed: (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates	76674: 12/27/00: approve settlement agreement (Phase III) 76227: 6/6/00: Delmarva to file revised compliance filings regarding supplier coordination tariff 76034: 3/29/00: approve settlement agreement (Phase II) 75680: 10/8/99: approve settlement agreement
8804/8794: 6/26/98	In the Matter of the Baltimore Gas And Electric Company's Proposed: (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates	80527: 1/25/06: approve settlement regarding industrials 76467: 922/00: deny rehearing application by Maryland Retailers Association and Building Owners and Managers 76180: 5/17/00: BGE to file revised compliance filings regarding supplier coordination tariff 76156: 5/12/00: BGE to submit tariffs 75757: 11/11/99: approval settlement agreement 75228: 5/11/99: suspend procedural schedule 75089: 3/26/99: approve the Office of the People's Counsel's motion to compel
8738: 10/10/96	In the Matter of the Commission's Inquiry into the Provision and Regulation of Electric Service	77666: 4/1/02: approves additional emissions and fuel mix requirements 77412: 12/11/01: adopts the PJM emissions and fuel mix tracking system for use by electric companies and electricity suppliers providing retail electricity (Emissions Disclosure Working Group) 77411: 12/11/01: approve Competitive Metering Working Group recommendations 76933: 5/11/01: modify universal service requirements 76931: 5/9/01: modify consumer protection requirements 76783: 2/27/01: reaffirm procedure schedule 76595: 11/20/00: modify universal service requirements 76467: 9/22/00: deny rehearing application by Maryland Retailers Association and Building Owners and Managers 76241: 6/20/00: set environmental information disclosure rules (Emissions Disclosure Working Group) 76139: 5/16/00: modify universal service requirements 76110: 4/27/00: modify consumer protection requirements 76049: 4/4/00: modify universal service requirements 76045: 4/4/00: pre-enrollment data and consumption history service data

Case Number/ Filing Date	Description	Order/ Order Date
		75959: 2/2/00: modify consumer billing requirements 75949: 2/9/00: approve Consumer Protection Working Group recommendations 75935: 1/31/00: approve Department of Human Resources proposal regarding universal service 75890: 1/12/00: approve Generic Technical Implementation Working Group recommendations 75889: 1/11/00: set customer enrollment transactions from suppliers 75722: 10/29/99: approve Competitive Billing Working Group recommendations 75608: 9/10/99: approve Supplier Authorization Working Group recommendations 75401: 8/3/99: approve Universal Service Working Group recommendations 75121: 4/18/99: approve Consumer Education Working Group recommendations 74561: 9/15/98: set schedule for roundtables 73901: 12/31/97: revise previous order to delay implementation dates for customer choice 73834: 12/3/97: establish a process to move toward retail electric competition 73496: 6/2/97: set procedural schedule 72938: 10/10/96: direct staff to make recommendations regarding retail electric competition
8678: 9/14/94	In the Matter of the Commission's Inquiry Regarding Electric Services, Market Competition and Regulatory Policies	72136: 8/22/95: introduction of retail electric competition is not in the public interest at this time 71459: 9/19/94: begin review of issues

Source: Public Service Commission

Appendix 2

States that Enacted Legislation or Issued Orders Establishing Electric Restructuring

State	Date Legislation Enacted/Order	Date Choice Begins/ Date ALL Customers Have Choice	Residential Price for 1996 (Cents) U.S. Average: 8.39	Relative Cost *	Status as of 2006** For Residential Customers
Maryland	*April 1999 (Legislation)*	*July 1, 2000/ July 1, 2002* *Rate caps mandated from 3.0 to 7.5% for four years*	*8.3*	*Average*	*Price caps ending 2005-08 – anticipate 72% increase (BGE)*
Arizona	May 1998 (legislation)	January 1, 1999 (delayed until late 1999)/ January 1, 2003 Rates caps after 10% reduction	9.0	Average	In transition period
Arkansas	April 1999 (legislation)	January 1, 2002/ June 30, 2003	7.8	Low	Repealed restructuring process in 2003
California	August 1997 (legislation)	March 31, 1998 Rate caps after 20% reduction	11.3	High	Suspended restructuring process after energy crisis in 2000-01***
Connecticut	April 1998 (legislation)	January 1, 2000 Rates frozen at 10% below 1996 levels	12.1	High	Price caps ending 2005-08
DC	1999 (legislation)	January 1, 2001	7.8	Low	Restructure complete by 2005

State	Date Legislation Enacted/Order	Date Choice Begins/ Date ALL Customers Have Choice	Residential Price for 1996 (Cents) U.S. Average: 8.39	Relative Cost *	Status as of 2006** For Residential Customers
Delaware	March 1999 (legislation)	October 1, 1999/ October 1, 2000 Rate caps after 7.5% reduction	8.9	Average	Price caps ending 2005-08 – 59% increase Delmarva when rate caps expired May 1, 2006
Illinois	December 1998 (legislation)	October 1, 1999/ May 1, 2002 Rates frozen 10 years and cut 20%, estimated savings $3 billion	10.4	High	Price caps ending 2005-08 – anticipate 20-55% increase ComEd)
Maine	May 1997 (legislation)	March 1, 2000 IOUS are limited to 33% of the market in their territories	12.6	High	Restructure complete by 2005
Massachusetts	October 1997 (legislation)	March 1, 1998 Rate reduction of 10-15%	11.3	High	Restructure complete by 2005
Michigan	2000 (legislation)	September 1999 January 1 2002	8.5	Average	In transition period
Montana	May 1997 (legislation)	July 1, 1998/ July 1, 2002	6.3	Low	Only allows for large industrials
Nevada	July 1997 (legislation)	March 1, 2000	6.9	Low	Only allows for restructuring only for large industrials
New Hampshire	May 1996 (legislation)	July 1, 1998 (delayed pending litigation)	13.6	High	In transition period
New Jersey	February 1999 (legislation)	August 1, 1999 Rate caps after 15% reduction for four years	12.0	High	Restructure complete by 2005 (19% rate increase in 2003 when rate caps expired)

State	Date Legislation Enacted/Order	Date Choice Begins/ Date ALL Customers Have Choice	Residential Price for 1996 (Cents) U.S. Average: 8.39	Relative Cost *	Status as of 2006** For Residential Customers
New Mexico	April 1999 (legislation)	January 1, 2001/ January 1, 2002	8.9	Average	Repealed restructuring process in 2003
New York	1998 (order)	January 1, 1999/ January 1, 2002 Various rate caps, depending on territory	14.0	High	Restructure complete by 2005
Ohio	June 1999 (legislation)	January 1, 2001 Rate caps after 5% reduction for five years	8.6	Average	Price caps ending 2005-08
Oklahoma	April 1997 (legislation)	July 1, 2002 (then delayed two years) Rate caps mandated	6.7	Low	Delayed restructuring process before ever implemented
Oregon	1999 (legislation)	March 1, 2002/delayed until March 1, 2003 Only large industrials may participate	5.7	Low	In transition period Except, allows for restructuring only for large industrials
Pennsylvania	November 1996 (legislation)	January 1, 1999/ January 1, 2001 Rate caps mandated	9.7	High	Price caps ending 2005-10 (73 – 129% increase PCP&L)
Rhode Island	August 1996 (legislation)	July 1, 1997/ July 1, 1998 Rate caps mandated	11.9	High	In transition period
Texas	June 1999 (legislation)	January 1, 2002 Rate caps after 6% reduction for three years	7.8	Low	Price caps ending 2005-08

State	Date Legislation Enacted/Order	Date Choice Begins/ Date ALL Customers Have Choice	Residential Price for 1996 (Cents) U.S. Average: 8.39	Relative Cost *	Status as of 2006** For Residential Customers
Virginia	February 1999 (legislation)	January 1, 2002/ January 1, 2004 Rate caps mandated	7.6	Average	Price caps ending 2005-08
West Virginia	1999 (legislation)	January 2001	6.4	Low	Delayed restructuring process

*Based on average rates, this gives an indication as to where electricity costs were in these states prior to the implementation of electric restructuring. (Low: $.05/kWh or less; Average: $.05 to $.06/kWh; High: $.07/kWh or higher.)

**Twenty-six other States (not listed above) that are not pursuing electric restructuring (have studied or are continuing to study): Alaska, Hawaii, Idaho, Colorado, Kansas, Vermont, North Dakota, South Dakota, Tennessee, Alabama, Georgia, South Carolina, North Carolina, Wisconsin, Washington, Utah, Wyoming, Nebraska, Minnesota, Iowa, Missouri, Louisiana, Mississippi, Florida, Indiana, and Kentucky.

***California: during the 2000-01 electric crisis, California had partly deregulated its power industry with controls removed from wholesale prices, but not from retail rates. Utility companies could not charge customers the high rates they paid for the power. Electricity prices increased significantly and blackouts occurred due to high natural gas prices; drought in the Northwest that reduced hydropower; and a manipulation of the markets by energy traders for Enron.

Source: Energy Information Administration, *Electric Power Annual, 1996*; U.S. Department of Energy – Electric Utility Restructuring Weekly Updates; NCSL Materials; Department of Energy; Federal Energy Management Program, 2006; and Legislation of States

Appendix 3

The Electric Customer Choice and Competition Act of 1999

	Provisions of the Act
Purpose of Subtitle	Purpose is to (1) establish customer choice of electricity supply and electricity supply services; (2) create competitive retail electricity supply and electricity supply services markets; (3) deregulate the generation, supply, and pricing of electricity; (4) provide economic benefits for all customer classes; and (5) ensure compliance with federal/State environmental standards.
Customer Choice Schedule **Other Preconditions**	Requires PSC to assess/approve each electric company's restructuring plan, oversee transition process, maintain reliability, ensure compliance with federal/State environmental regulations, be fair to interested parties, and provide economic benefits to all customer classes. Before the implementation of customer choice, requires PSC, by regulation or order to (1) require each electric company and supplier to provide adequate and accurate customer information, including, every six months, fuel mix and emissions information; (2) require unbundling of rates, charges, and services into standardized categories; (3) prevent unauthorized disclosure of customer billing, payment, and credit information; (4) require a universal service program; (5) prevent discrimination by electric company in favor of own supply and other self-dealing; and (6) maintain environmental standards, adapt existing programs, and develop new programs to ensure compliance with federal and State environmental protection standards. Requires PSC, by 7/1/00, to ensure the creation of competitive electricity supply with appropriate customer safeguards and to require by 7/1/00 (1) code of conduct between electric company and affiliate providing electricity supply or services; (2) access to electric company's transmission and distribution system on a nondiscriminatory basis; (3) appropriate complaint/enforcement procedures and other necessary safeguards; and (4) require functional, operational, structural, or legal separation between electric company's regulated and nonregulated businesses or affiliates (does not apply to municipal electric utilities). (Requires PSC to report on 12/1/99.) 7/1/00: One-third of residential customer class of each electric company; 7/1/01: two-thirds; 7/1/02: 100%. 1/1/01: 100% of industrial and commercials; 7/1/03: 100% customers of electric cooperatives. PSC may have separate schedule for municipal corporations that elect to make territory open to customer choice. For good cause and if in public interest, PSC may accelerate or delay the initial implementation date by up to three months and accelerate other dates and phase-in percentages.
Municipal Electric Utilities and Electric Cooperatives	Allows PSC to adopt a separate schedule for implementation of customer choice (1) municipal electric utilities that elect to make their service territory available (not required); and (2) electric coops (electric coops must offer 100% customer choice by 7/1/03).

	Requires municipal electric utility to file a proposed plan and schedule with PSC if the municipal electric utility elects to allow customers choice; PSC may consider distinguishing qualities. Prohibits the requirement of functional, operational, structural, or legal separation of the regulated and nonregulated operation of the municipal electric utility. Requires each municipal electric utility to report by 10/1/03 to the General Assembly its status as of 7/1/03 regarding allowing customer choice in its service territory or its intention to do so. Allows suppliers to serve customers in municipal electric utility distribution territory if the municipal electric utility serves outside of its territory. Allows municipal electric utilities and electric coops to offer SOS in their distribution territories after 7/1/03. SOS obligations cease after 12 months notice to PSC.
Aggregators	Defines "aggregator" to mean: an entity or individual that acts on behalf of customers to purchase electricity. Provides that an aggregator is an electric supplier (as an electric supplier, it must be licensed). Does not include: an entity that purchases for its own use or for its affiliates; or a municipal electric utility serving only in its distribution territory, or a combination of governmental units that purchase electricity for use by the units. Prohibits a county or municipal corporation from acting as an aggregator unless PSC determines that there is not sufficient competition within the boundaries of the county or municipal corporation.
Certificate of Public Convenience and Necessity (CPCN)	Continues PSC approval of CPCN process for (1) construction or exercise of condemnation right for construction of a generating station (also, prohibits the exercise of condemnation unless PSC finds that capacity is necessary to ensure a sufficient supply of electricity to customers in the State); and (2) stability and reliability for generating stations. Continues PSC/Department of Natural Resource's involvement in planning possible and proposed sites; removes PSC mandate to consider demand need for generating stations; and removes PSC/ Department of Natural Resource's involvement to evaluate long-range plans of electric companies regarding generation.
System Reliability	Maintains, in awarding a CPCN license, PSC's consideration of the stability and reliability of the electric system. Requires PSC's assessment and approval of an electric company's restructuring plan, transition oversight, and regulation provide that electric system reliability is maintained. Makes reliability of regulated electric services a mandatory quality of any alternative form of regulation. Continues reliability of distribution system to be regulated by PSC.
Consumer Education	Requires PSC, with the Office of the People's Counsel and other parties, to order consumer education program; customer education program ends 6/30/02. Requires Division of Consumer Protection to develop/maintain information regarding rates and services for small commercial and residential electric customers – allow comparison of rates and provide availability of information. Authorizes $6 million for fiscal 2000 from the Revenue Stabilization Fund to be used for educating consumers. Requires PSC to use allocated funds to implement a program. Requires PSC to report by 9/1/99 on recommended funding level (between $3 million and $6 million) and method of funding for fiscal 2001; and report by 9/1/00 for funding for fiscal 2002.

Distribution Company Requirements	Requires electric company in a distribution territory to (1) provide and to be responsible for distribution in that territory; and (2) provide distribution services in its territory to all customers and electricity suppliers on rates, terms of access, and conditions that are comparable to the electric company's own use. Continues to require electric company to maintain reliability of its system. Requires electric company to connect customers and deliver electricity on behalf of suppliers. Continues tariff schedule of rates of regulated service to be just and reasonable. But, allows PSC to regulate regulated services of an electric company through alternative forms of regulation. Allows PSC to adopt an alternative form of regulation if it finds that it protects consumers, ensures quality, availability and reliability, and is in the public interest. Requires electric company to provide SOS. Requires filing of tariff schedule for SOS. Requires PSC to determine terms, conditions, and rates of SOS. Requires PSC to require each electric company to adopt a code of conduct approved by PSC to prevent regulated service from subsidizing nonregulated business or affiliate of electric company.
Deregulation of Generation, Supply, and Sale of Electricity	On or after the initial implementation date and after electric company* has transferred its generation assets and facilities to an affiliate or sold the generation facilities and assets to a nonaffiliate, generation may not be regulated as an electric company service or function, except (1) to establish price for SOS; and (2) review and approve transfers of generation assets. However, provides that the costs of nuclear generation facilities and purchased power contracts that, as part of a settlement approved by PSC, remain regulated or are recovered through the distribution function. *NOTE: An investor-owned electric company whose retail peak load in the State on 01/01/99 was less than 1,000 MW would not have to transfer or sell its generation facilities and assets until 1/1/01 to have its generation deregulated. Allows PSC to establish the price for SOS and review/approve transfers until the later of the date when (1) all customers have choice; (2) amount of transition costs arising from the generation assets to be transferred has been determined by PSC; and (3) obligation to provide SOS terminates. **Supply:** Requires PSC to assess the amount of electricity generated in Maryland, as well as the amount imported from other states in order to determine whether a sufficient supply is available. Requires PSC, on January 1, in 2001, 2003, 2005, and 2007, to report on the supply and any recommendations.
Licensure of Electricity Suppliers	Requires licensing for engaging in business of selling electricity or electricity supply services, including several requirements to obtain a license: proof of technical and managerial competence; proof of compliance with applicable FERC and regional system operator; certification of compliance with applicable federal and State environmental laws and regulations that relate to generation; payment of fee; proof of financial integrity; posting of a bond. Includes: aggregator, broker, marketer, electricity supplier, competitive billing servicer, competitive metering servicer.

	Does not include: electric company providing SOS, municipal electric utility serving solely in its distribution territory, persons who supply solely to occupants of a building through internal distribution system; and on-site generation electricity. Requires PSC to adopt regulations/issue orders to (1) protect consumers, electric companies, and suppliers from anti-competitive/abusive practice; (2) require suppliers to provide adequate and accurate customer information; and (3) establish restrictions on telemarketing, procedures for contracting with customers, requirements relating to deposits/billing/collections, provisions for referral of a delinquent account by a supplier to SOS, and procedures for dispute resolution. Prohibits supplier from discrimination against any customer based on certain factors; prohibits refusing to provide service except by supplier's economic/business purpose. Allows revoking/suspending of license, order refund/credit to a customer, and civil penalties. Allows PSC access to books and records to resolve complaints. Requires suppliers to (1) be included in bearing costs/expenses of PSC; (2) subject to federal/State environmental laws; and (3) post on Internet information about services/rates.
Rate Reduction and Cap	Requires PSC to REDUCE residential rates for each investor-owned electric company by amount between 3% and 7.5% of base rates, as measured on 6/30/99. This reduction begins on initial implementation date FOR ALL RESIDENTIAL CUSTOMERS (regardless of when they have choice) and remains in effect for four years. Requires four-year "CAP" FOR ALL CUSTOMER CLASSES on total of rates at the actual level of rates in effect or authorized by PSC on the date immediately preceding initial implementation date in the electric company's distribution territory. Rate cap includes: transition costs, costs included in rates on 1/1/00; and universal service. Rate cap does not include: other costs added after 1/1/00. Requires PSC to determine the allocation of reduction among generation, transmission, and distribution residential rate components. Requires PSC to consider achieving the reduction (1) expiration of surcharges; (2) changes in the electric company's tax liability; (3) cost of service determinations order by PSC; (4) net transition costs or benefits; (5) effect on the competitive electricity supply market; (6) whether the rate reduction and cap will unduly impair the electric company's financial condition; (7) costs associated with universal service program; and (8) interests of public, including shareholders. Allows PSC, within the parameters, to increase/decrease actual rate reduction. Allows for the recovery of extraordinary costs based on circumstances of individual electric companies if PSC determines necessary and in public interest. Prohibits PSC from increasing rates for nonresidential in calculating reduction for residential. Provides that rate reduction does not apply to an electric company that has a settlement that is equally protective of ratepayers. As part of a settlement, allows PSC to approve a cap for a different period or an alternative price protection plan that is equally protective of ratepayers.

Standard Offer Service (SOS)	Requires PSC to determine the terms, conditions, and rates of SOS. From the initial implementation date, requires an electric company to offer SOS until 7/1/03. Provides that customers are considered to have chosen SOS if not allowed to choose, electricity is not delivered, cannot be arranged, does not choose, chooses the SOS, or has been denied service or referred to the SOS by a supplier. If PSC finds that competition does not exist or that no acceptable competitive proposal has been received to supply SOS customers, allows PSC to extend the electric company's obligation to provide SOS for residential and small commercial at a market rate that permits recovery of the verifiable prudently incurred costs to procure or produce the electricity plus a reasonable return. This finding is to be reexamined annually. Requires PSC by 7/1/01 to adopt regulations/issue orders to establish procedures for the competitive selection of suppliers to provide SOS. Unless delayed, it takes effect by 7/1/03. Allows an electric company to procure its obligation of SOS from a supplier. Requires PSC to adopt regulations/issue orders to establish provisions providing for the referral of a delinquent account by a supplier to SOS.
Customer Information/ Bill Disclosure	Before customer choice, requires PSC by regulation/order to require each electric company and electric supplier to provide adequate and accurate information on available electric services, including: disclosure on a semi-annual basis of fuel mix and emissions (electricity from coal, natural gas, nuclear, oil, hydroelectric, solar, biomass, wind, and other resources); or of a regional fuel mix average. Prohibits electric company and supplier from disclosing billing, payment, credit, and usage information without customer permission. Prohibits supplier or others from, without first obtaining customer's permission, making a change in supplier or adding a new charge for a new or existing service or option. Requires PSC to adopt regulations/issue orders to require suppliers to provide adequate and accurate customer information to enable customers to make informed choices regarding the purchase of electricity services. Requires electricity bills (competitive and regulated) to be prepared and issued in accordance with PSC regulations/orders and provide (1) identity and phone number of supplier; (2) sufficient information to evaluate prices and services; and (3) information identifying whether the price is regulated or market. Before customer choice, requires PSC by regulation/order to require the unbundling of electric company rates, charges, and service into standardized categories, including: distribution, transmission, transition charge or credit, universal service program charge, customer charges, taxes, and other.
Universal Service	Requires PSC to establish a universal service program on a statewide basis to assist electric customers with annual incomes at or below 150% of the federal poverty level. Authorizes DHR (through the Maryland Energy Assistance Program) to contract (with input from a panel or roundtable) with a for-profit or nonprofit Maryland corporation existing as of 7/1/99 to administer the program. Requires PSC to have oversight. Requires the components of the program to include (1) bill assistance (at a minimum of 50% of the determined need); (2) low-income weatherization; and (3) retirement of arrearages incurred prior to initial implement date.

	Requires all customers to contribute to the program through a charge; requires PSC to determine a fair allocation among classes. Requires unexpended funds to be returned. Requires full recovery of costs for universal service by surcharge under the cap. Prohibits the assessment of surcharge on kWh basis. Requires PSC on 12/1/99 (and annually) to report on a recommended funding level and impact on rates and impact using other federal poverty levels. Sets funding as follows: $34 million each year for three years ($24.4 million from industrials/commercials; $9.6 million from residentials); beyond depends on action of General Assembly, after considering recommendations by PSC (information related to first three years, retirement of arrearages; and low-income assistance in rates prior to choice). Prohibits suppliers and electric companies from terminating for three years the supply of electricity because of an outstanding balance of arrearages on initial implement date without customer authorization. Creates Universal Service Program Special Fund.
Transfer of Generation Facilities and Assets	Authorizes electric company to transfer generation facilities and assets to an affiliate. In connection with the recovery of transition costs (1) prohibits PSC from requiring electric company to divest itself of generation asset or prohibit an electric company from divesting itself voluntarily of a generation asset; and (2) prohibits the transfer from affecting or restricting the PSC's determination of the value of a generation asset for purposes of transition costs. Allows PSC to review/approve a transfer for the sole purpose of determining that (1) appropriate accounting was followed; (2) transfer does not or would not result in undue adverse effect on proper functioning of a competitive market; and (3) appropriate transfer price and rate-making treatment. PSC must act on a transfer within 180 days after filing of application and supporting information. Allows PSC to review until the later of the date when (1) all customers have choice; (2) amount of transition costs arising from generation assets to be transferred has been determined by PSC; and (3) PSC has terminated the obligation to provide SOS if it is further extended.
Transition and Stranded Cost Recovery	Requires electric company to have a fair opportunity to recover "all prudently incurred and verifiable net transition costs, subject to full mitigation." Requires PSC determination of stranded costs. Allows competitive transition charge (CTC) to be included by those who access transmission and distribution. Requires costs allocated by PSC to customer class in a way that avoids interclass or intraclass subsidy. PSC determines the length of time CTC is to be included in bills. Exempts certain on-site self generators from CTC. Requires PSC to establish procedures for annual review of CTC and adjust for under recovery or over recovery. Allows PSC to approve an adjustment ("true-up") that factors generation asset sales by electric company to a nonaffiliate consummated before 6/30/05. In determining transition costs or benefits, requires PSC to consider (1) book value and market value; (2) auctions and sales of comparable assets; (3) appraisals; (4) revenue the company would receive under rate-of-return regulation and in a restructured electricity supply market; and (5) computer simulations provided to PSC. Requires PSC to determine allocation of

	transition costs or benefits between shareholders and ratepayers based on several factors. Requires PSC to report to General Assembly by 12/1/99 on any stranded cost/benefit determinations. In connection with the recovery of transition costs, prohibits PSC from ordering or prohibiting divestiture of a generation asset. Allows electric company to apply for qualified rate order after July 1, 1999 and assessment of Intangible Transition Charge.
On-site Generators	Defines on-site self-generated electricity as electricity that is not transmitted or distributed over an electric company's transmission and distribution AND is generated at a facility-owned or operated by an electric customer or operated by a designee of the owner who, with other tenants of the facility, consumes at least 80% of the power generated for the facility each year. Exempts certain on-site self generators from CTC if (1) existing facilities installed generating capacity as of 1/1/99; or (2) contract for generating capacity has been executed before 1/1/99 or on-going good-faith negotiations have been going on as of 9/29/99 for generating capacity. Also, allows exemption from CTC for a facility with a capacity of 500 kWh or less for (1) up to the first 80 MW on a statewide basis of aggregate generating capacity; (2) generating capacity installed between 1/1/00 and 12/31/03 that derives electricity from fuel cells, photvoltaics, wind machines, or micro turbines and has energy conversion efficiency greater than 40%; or (3) generating capacity installed after 1/1/04 that derives electricity from fuel cells, photvoltaics, wind machines, or micro turbines and has energy conversion efficiency greater than 50%.
Demand Side Mgt (DSM)/ **Energy Conservation/ Efficiency**	Continues and modifies PSC mandate to require each electric company to include in their long-range plans <u>adequate, cost-effective</u> provisions to promote energy conservation and decrease demand for <u>regulated service</u> from customers. Continues PSC mandate to evaluate the cost effectiveness of electric company's investments into energy conservation. This evaluation shall include (1) weatherization programs; (2) utilization of renewable energy resources; (3) promotion and use of cogeneration and wastes; and (4) widespread public promotion of energy conservation programs. Continues PSC mandate to develop and implement programs and services to encourage and promote efficient use of and conservation of energy. Provides that adoption of choice does not adversely impact the continuation of cost-effective energy conservation and efficiency programs. Requires PSC, in consultation with the Maryland Energy Administration, to report by 2/1/01 on the status of programs and services and a recommendation for funding. (Criteria to consider: impact on jobs, impact on environment, impact on rates, and cost effectiveness.) Requires full recovery of costs for DSM/conservation by surcharge. Costs not included in rates on 1/1/2000 are not included in the cap.
Environment **Environment Trust Fund (ETF)**	Requires PSC, in consultation with the Maryland Department of the Environment, to adopt appropriate measures to maintain environment standards, adapt existing programs, and develop new programs as appropriate to ensure compliance with federal and State environmental protection standards. Requires, to obtain licensure as electricity supplier, a certification of compliance with applicable federal and State environmental laws and regulations that relate to generation. Does not change existing standards for emissions. Current requirements for Nox: all utilities required to meet Reasonably Available Control Technology standards, set on a case-by-case basis, based upon the type and size of operation. New utilities must meet New Source Performance Standards.

	Requires electric companies to conduct a study that tracks shifts in generation and emissions as a result of restructuring the electric industry. Requires the Maryland Department of the Environment to study, if the department determines from the above study that emissions levels impose a higher emission burden in Maryland, the appropriateness, constitutionality, and feasibility of establishing an air quality surcharge or other mechanism to protect Maryland's environment in connection with choice. Continues the Environmental Trust Fund, its current purpose, and the current surcharge. However, makes current surcharge apply to electricity distributed (instead of generated) in the State. Extends the sunset from fiscal 2000 to 2005. Current purpose provides (1) the Department of Natural Resources with funds for the Power Plan Research Program; and (2) Maryland Energy Administration with funds for studies related to the conservation or production of electric energy.
Renewable Energy Resources (RER)	Defines "renewable energy resources" to mean; solar, wind, tidal, geothermal, biomass, hydro, digester gas, waste-to-energy. Before customer choice, requires PSC by regulation/order to require each electric company and electric supplier to provide adequate and accurate information on available electric services, including: disclosure on an annual basis of fuel mix and emissions (electricity from renewable energy resources, coal, natural gas, nuclear, oil, hydroelectric, solar, biomass, wind, and other resources); or of a regional fuel mix average. Requires an electric company to continue to purchase electricity under any contract in effect of 1/1/99 with a renewable energy resource facility located in the State until the later of the expiration of the contract or the expiration or satisfaction of bonds existing on 1/1/99 supporting the facility. Requires investor-owned electric companies to continue to provide at least the same percentage of electricity from available renewable energy resources, at a reasonably comparable cost, as the electric company provided in 1998. Requires PSC, in consultation with MEA, to report by 2/1/00 on the feasibility of requiring a renewable portfolio standard and the estimated costs and benefits.
Market Power/ Noncompetitive Conduct	Requires PSC to order an electric company to adopt policies/practices to prevent undue discrimination or unreasonable preference in favor of own supply, affiliates, etc., and to prevent self-dealing that could result in noncompetitive prices. Requires PSC to adopt regulations/issue orders designed to ensure creation of competition of competitive supply – PSC shall require: appropriate code of conduct between electric company and affiliate; access by suppliers to T&D on nondiscrimination; functional, operational, structural, and legal separation. Requires PSC to require each electric company to adopt code of conduct approved by PSC to be determined by PSC to prevent regulated service customers from subsidizing service of unregulated business or affiliate of electric company. Requires PSC to monitor market power or other anti-competitive conduct and authorizes PSC to investigate on complaint or own motion. Authorizes PSC to take remedial action if market power or other anti-competitive conduct is preventing customers from realizing market benefits. Requires PSC to include antitrust principles in performing its analysis. Requires PSC to cooperate with and share information with the Antitrust Division of the Attorney General. Provides that rights/remedies supplement any other rights/remedies that may exist under other law.

Consumer Protections	For licensure, allows suspension/revocation of license, order refund/credit to a customer, or civil penalties for failure to comply with certain consumer protections. Allows PSC to investigate on own or on complaint. Requires suppliers to provide PSC access to books to resolve complaint. Just cause includes (1) intentionally providing false information to PSC; (2) slamming, failing to provide electricity; (3) committing fraud or engaging in deceptive practices; (4) failure to maintain financial integrity; (5) violating PSC regulation/order, failing to pay State or local taxes; (6) violating State public service utility law or other State consumer protection law; (7) conviction of felony by licensee; and (8) suspension/revocation of a license by any State or federal authority. Sets civil penalties up to $10,000/violation; each date a violation continues is a separate violation. Allows PSC to order a supplier to cease adding/soliciting customers. Prohibits supplier from being changed or from adding a new charge for a new or existing service without the customer's permission (slamming/cramming). Prohibits electricity suppliers from engaging in marketing, advertising, or trade practices that are unfair, false, misleading, or deceptive. Provides that title may not be construed as preventing the application of State and federal consumer protection and antitrust laws to electric companies, their affiliates, and to suppliers.
Competitive Billing and Metering	Except for municipal electric utilities and electric coops (1) competitive billing shall begin 7/1/00; and (2) competitive metering for large customers shall begin on 1/1/02 and for all customers on 4/1/02 (or earlier if requested by electric company). Requires a person (other than electric company or municipal electric utility) who engages in the business of competitive billing in a local jurisdiction that assesses a local energy tax to hold a local license. Allows the local jurisdiction to require the applicant/licensee to (1) hold a license issued by PSC; (2) post a bond; and (3) have a resident agent in the State. Allows the local jurisdiction to revoke/suspend the local license if the licensee fails for 15 days to pay or remit all of the local energy taxes due. Prohibits charging of a local license fee.

Source: Chapter 3 and 4 of 1999 (Public Utility Companies Article, Title 7)

Appendix 4

Electricity Distribution Service (DS) and Standard Offer Service (SOS) Rate Restrictions and Obligation to Provide SOS, Effective July 1, 2000

BGE (Baltimore Gas and Electric Co.)	Rate Reduction: average 6.5% for *residential* only Rates Frozen for DS and SOS: *residential* through 6/30/06**; *commercial* through 6/30/04; and *large industrial* through 6/30/02 Obligation to provide SOS: *residential* through 5/31/10; *Type I commercial* through 5/31/08; Type II through 5/31/06; *Type II-A and B commercial* through 5/31/07; *large industrial* through 6/1/05
PEPCO (Potomac Electric Power Co.)	Rate Reduction: 7% Rates Capped for DS and SOS: *residential* and *commercial* through 6/30/04 Obligation to provide SOS: *residential* through 5/31/08; *Type I commercial* through 5/31/08; Type II through 5/31/06; *Type II-A and B commercial* through 5/31/07; *large industrial* through 6/1/05
Delmarva (Conectiv) Power and Light Co.	Rate Reduction: 7.5% for *residential* only Rates Frozen for DS/SOS: *residential* through 6/30/04; *commercial* through 6/30/03 Obligation to provide SOS: *residential* through 5/31/08; *Type I commercial* through 5/31/08; Type II through 5/31/06; *Type II-A commercial* through 5/31/07; *large industrial* through 6/1/05
Allegheny Power (Potomac Edison Co.)	Rate Reduction: 7% for *residential* only Rates Capped for DS: *residential* and *commercial* through 6/30/04 Rates Capped for SOS: *residential* through 12/31/08; *commercial* through 12/31/04 Obligation to provide SOS: *residential* through 12/31/12; *Type I commercial* through 12/31/08; Type II through 12/31/06; *Type II-A commercial* through 5/31/07; *large industrial* through 6/1/05
Southern Maryland Electric Coop (SMECO)	Rates Capped for DS: *residential* and *commercial* through 12/31/04; rates then set by commission through 12/31/08 Rates Frozen for SOS: *residential* and *commercial* through 12/31/04; service then offered at market-based prices through 12/31/08
Choptank Electric Cooperative	Rates Capped for DS: *residential* and *commercial* through 6/30/05 Rates Frozen for SOS: *residential* and *commercial* through 12/31/05; service then offered at market-based prices through 12/31/10

**In order 80638 (case 9052) issued March 6, 2006, the Public Service Commission estimated that the price freeze enacted in the BGE service area resulted in substantial savings to BGE residential customers, estimated to be approximately $1 billion; customers do not pay back any of these savings.

Source: Public Service Commission

Appendix 5

SOS Bidding Process and Results Impact on Residential Customers

PEPCO

	Percent of all Pepco Residential Customers	Average Current Annual Bill	Percent Increase in Total Annual Bill	Dollar Amount Increase in Annual Bill	Percent Increase in SOS Power Supply Part of Bill
Bids in Early 2004 (EFFECTIVE July 1, 2004 – May 31, 2005)					
Standard Rate Customers with Electric Heat	25%	$1,152	19%	$218.93	31%
Standard Rate Customers Who Do Not Have Electric Heat	63%	$870	14%	$121.86	24%
Time-of-use Customers with Electric Heat	3%	$1,941	24%	$465.74	36%
Time-of-use Customers Who Do Not Have Electric Heat	9%	$1,456	14%	$203.90	21%
All Residential Customers	100%	$1,027	16%	$164.28	26%

Bids in Early 2005 (EFFECTIVE June 1, 2005 – May 31, 2006)					
Standard Rate Customers with Electric Heat	25%	$1,347	5%	$63.96	7%
Standard Rate Customers Who Do Not Have Electric Heat	63%	$958	4%	$41.04	6%
Time-of-use Customers with Electric Heat	3%	$2,372	5%	$116.28	7%
Time-of-use Customers Who Do Not Have Electric Heat	9%	$1,651	5%	$79.08	7%
All Residential Customers	100%	$1,164	4.5%	$52.68	6.6%

Bids in Early 2006 (EFFECTIVE June 1, 2006 – May 31, 2007)					
Standard Rate Customers with Electric Heat	25%	$1,413	40%	$561	60%
Standard Rate Customers Who Do Not Have Electric Heat	63%	$998	37%	$368	58%
Time-of-use Customers with Electric Heat	3%	$2,486	43%	$1,062	60%
Time-of-use Customers Who Do Not Have Electric Heat	9%	$1,729	40%	$695	58%
All Residential Customers	100%	$1,215	39%	$468	59%

Conectiv

	Percent of All Conectiv Residential Customers	Average Current Annual Bill	Percent Increase in Total Annual Bill	Dollar Amount Increase in Annual Bill	Percent Increase in SOS Power Supply Part of Bill
Bids in Early 2004 (EFFECTIVE July 1, 2004 – May 31, 2005)					
Customers with Electric Heat	48%	$1,284	12%	$154.44	19%
Customers Who Do Not Have Electric Heat	52%	$942	11%	$107.52	19%
All Residential Customers	100%	$1,122	12%	$130.80	19%

Bids in Early 2005 (EFFECTIVE June 1, 2005 – May 31, 2006)					
Customers with Electric Heat	48%	$1,423	5.9%	$84.56	8.7%
Customers Who Do Not Have Electric Heat	52%	$1,040	5.7%	$58.80	8.7%
All Residential Customers	100%	$1,240	5.8%	$71.84	8.7%

Bids in Early 2006 (EFFECTIVE June 1, 2006 – May 31, 2007)					
Customers with Electric Heat	48%	$1,512	36%	$546	52%
Customers Who Do Not Have Electric Heat	52%	$1,101	35%	$380	52%
All Residential Customers	100%	$1,315	35%	$464	52%

BGE

Bids in Early 2006 (EFFECTIVE July 1, 2006 – May 31, 2007)

	Percent of all BGE Residential Customers	Average Current Annual Bill	Percent Increase in Total Annual Bill	Dollar Amount Increase in Annual Bill	Percent Increase in SOS Power Supply Part of Bill
Standard Rate Customers	92%	$995	71%	$709	131%
Time-of-use Rate Customers	8%	$1,468	77%	$1,138	145%
All Residential Customers	100%	$1,033	72%	$743	132%
Standard Rate Customers with Electric Heat	24%	$1,421	75%	$1,071	136%
Standard Rate Customers Who Do Not Have Electric Heat	68%	$848	69%	$584	128%
Time-of-use Customers with Electric Heat	4%	$1,776	80%	$1,422	148%
Time-of-use Customers Who Do Not Have Electric Heat	4%	$1,208	74%	$894	141%
All Residential Customers	100%	$1,033	72%	$743	132%
All Residential Customers With Electric Heat	28%	$1,472	76%	$1,121	138%
All Residential Customers Who Do Not Have Electric Heat	72%	$867	69%	$600	129%
All Residential Customers	100%	$1,033	72%	$743	132%

SMECO

Residential Bill under 2004 Contract and Managed Power Supply Portfolio for 2005-06

All Residential Customers	Percent of All SMECO Residential Customers	Average Current Annual Bill (1,000 kWh)	Percent Increase in Total Annual Bill	Dollar Amount Increase in Annual Bill	Percent Increase in SOS Power Supply Part of Bill
Dec 04	100%	$891			
Jan 05	100%	$1,092	22%	$200	41%
Feb 05	100%	$1,093	0%	$1	0%
Mar 05	100%	$1,151	5%	$58	8%
April 05	100%	$1,154	0%	$3	0%
May 05	100%	$1,180	2%	$26	4%
June 05	100%	$1,269	8%	$89	2%
July 05	100%	$1,276	1%	$7	1%
Aug 05	100%	$1,344	5%	$68	8%
Sep 05	100%	$1,377	3%	$34	4%
Oct 05	100%	$1,452	5%	$75	8%
Nov 05	100%	$1,360	-6%	($92)	-2%
Dec 05	100%	$1,372	1%	$11	4%
Jan 06	100%	$1,317	-4%	($55)	-6%
Feb 06	100%	$1,302	-1%	($14)	-2%
March 06	100%	$1,398	7%	$96	10%
April 06	100%	$1,412	1%	$14	1%

In the Matter of the Commission's Inquiry into the Competitive Selection of Electricity Supplier/Standard Offer Service: Case 8908

Notes: Tranche bids for July 1, 2006 – May 31, 2007 were on: December 5, 2006, January 23, February 21, 2006. In total, Maryland utilities requested electric supply proposals totaling 8,259 MW of SOS load (AP 344); BGE 5,188; Delmarva 684; Pepco 2,044 – of this amount, 5,003 MW was residential: 2,940.4 for 11 month to 1 year contracts; 1,231.3 MW for 23 month to 2 year contracts; and 831.3 MV for 35 month contract.

Source: Public Service Commission

Appendix 6

BGE Residential Customers Comparison of Plans
Impact on Standard Rate Electric Rates Beginning July 1, 2006

	PSC **March 6, 2006 Plan**	**Legislative Proposal** **HB 1525 of 2006**	**Governor/PSC** **April 28, 2006 Plan**	**Senate Bill 1(Chapter 5)** **Special Session 2006**
Status of Plan, as of June 12, 2006	Indicated as an option by the Circuit Court for Baltimore City in its May 30, 2006 order – as of Jnne 2, 2006, PSC continued this plan on the docket	Did not pass during the 2006 session	Appealed to Circuit Court for Baltimore City – not indicated as an option by the court in its May 30, 2006 order: Plan is vacated	Proposed at the special session, June 14, 2006
Phase-in Rate **(without plan: average 72%)**	21% July 1, 2006, with varied monthly increments through March 1, 2007 (similar to a budget billing approach – shaves peaks and adds to shoulder months)	15% July 1, 2006 29% June 1, 2007	19.4% July 1, 2006 5% Jannary 1, 2007 25% June 1, 2007	15% July 1, 2006 Subsequent phase-in increases start June 1, 2007 or full market, at customer's option
Market Rates Begin	March 1, 2007 (8 months after July 1, 2006)	January 1, 2008 (an estimated 16% increase) (18 months after July 1, 2006)	January 1, 2008 (an estimated 9% increase) (18 months after July 1, 2006)	No later than January 1, 2008 but not before June 1, 2007
Payment of Deferral Begins and Length of Recovery Period	March 1, 2007 15 months recovery period (1 extra year for low-income customers)	January 1, 2007 10 years recovery period	June 1, 2007 24 months recovery period (1 extra year for low-income customers)	January 1, 2007 10 years recovery period
Plan Date Ends (End of Deferral Period)	May 31, 2008	December 31, 2016	May 31, 2009	May 31, 2017

	PSC March 6, 2006 Plan	Legislative Proposal HB 1525 of 2006	Governor/PSC April 28, 2006 Plan	Senate Bill 1(Chapter 5) Special Session 2006
Opt-in or Opt-out of Phase-in and Deferral	Opt-out	No option (must participate in the phase-in and the deferral)	Opt-in	No option (must participate in the initial 11-month phase-in)
Deferred Amount to be Paid Eventually	Yes But, credits may be available through merger proceeding	Yes But, credits may be available through merger proceeding	Yes But, credits may be available through merger proceeding	Yes But, credits available in the legislation and may be available through merger proceeding
Total Cumulative Deferred Amount of Electric Charges, including Interest Charges	Number of months when deferral is growing: 8 months Number of months/years to repay deferral: 15 months Principal: $257 million Interest: 8 million Total $265 million (short-term loan: interest 5%) Assumes 100% participation	Number of months when deferral is growing: 18 months Number of months/years to repay deferral: 10 years Principal: $725 million Interest: 132 million Total $857 million (securitization) 100% participation	Number of months when deferral is growing: 18 months Number of months/years to repay deferral: 24 months Principal: $588 million Interest: 0 Total $588 million (short-term loan: interest 0% per PSC – would have been $24 million if interest were allowed at 5%) Assumes 100% participation	Number of months when deferral is growing: 11 months Number of months/years to repay deferral: 10 years Principal: $573 million Interest: 109 million Total $682 million (securitization) 100% participation

	PSC March 6, 2006 Plan	Legislative Proposal HB 1525 of 2006	Governor/PSC April 28, 2006 Plan	Senate Bill 1(Chapter 5) Special Session 2006
Total Cumulative Credits (may be contingent on the merger)	$0 (merger proceedings not addressed: PSC has separate proceedings)	$600 million (realized over a 10-year period) Only if merger is approved:* – decommissioning $18.6 million per year – return component $20 million per year – merger savings $21.4 million per year	$600 million as offered by BGE/Constellation (realized over a 10-year period) (not in order; instead, as a placeholder in separate proceedings) Only if merger is approved:* – decommissioning $18.6 million per year – return component $20 million per year – merger savings $21.4 million per year	$386 million or more (realized over a 10-year period) Not based on merger: – decommissioning $18.6 million per year – return component $20 million per year Potential savings from merger and PSC proceedings*
Impact on Average Customer per Month Beginning July 1, 2006*	$17/month increase (21% increase) for a few months, with varied monthly increments through March 1, 2007	$12/month increase (15% increase) until June 1, 2007	$16/month increase (19.4% increase) until January 1, 2007	$12/month increase (15% beginning July 1, 2006 through May 31, 2007)

	PSC March 6, 2006 Plan	Legislative Proposal HB 1525 of 2006	Governor/PSC April 28, 2006 Plan	Senate Bill 1(Chapter 5) Special Session 2006
Impact on Average Customer per Month for Deferral Payback	Deferral pay back Principal $15.60 Interest .49 Total $16.09 Credits Not based on merger $0 Based on merger $0 Net deferral charge $16.09 Over 15 months	Deferral pay back Principal $5.15 Interest 1.20 Total $6.35 Credits over 10 yrs Based on merger $4.40 Net charge w/o merger $6.35 Net w/merger $1.95 Over 10 years	Deferral pay back over 2 yrs Principal $22.31 Interest 0 Total $22.31 Credits over 10 years Based on merger $4.40 Over 2 years: Net charge w/o merger $22.31 Net w/merger $17.91 Net charge after second yr $0	Deferral pay back Principal $4.07 Interest 0.95 Total $5.02 Credits over 10 years Not based on merger $2.83 Merger saving – based on PSC determinations Net deferral charge $2.19 Over 10 years

Note: Without any plan average current annual bill of $995 increases about $708 (or by $59/month) = $1,703 per year (71-72% increase); average bill is about 12,000 kWh per year with 4,500 kWh in four summer months and 7,500 kWh in eight nonsummer months; BGE has approximately 1.1 million residential customers.

*The filing for the proposed merger of FPL and Constellation was terminated in October 2006.

Source: Department of Legislative Services, October 2006

Appendix 7

Senate Bill 1 (Chapter 5 of 2006, Special Session) Public Service Commission – Electric Industry Restructuring

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Public Service Commission Commissioners
(Section 1: Section 2-102; 2-103; 2-113; Section 12 and 14)

- The term of office for the five commissioners serving as of June 30, 2006, ends June 30, 2006.

- The new term of all of the five commissioners begins July 1, 2006. Expiration of new terms is staggered beginning at the end of fiscal 2007.

- For this time only, a new chair and 4 other commissioners are appointed by the Governor from a list of 3 for the chair and 10 names for the other commissioners provided by the Presiding Officers. (Future appointments are solely by the Governor with the consent of the Senate.)

- The Governor has two weeks to make the new appointments; otherwise the Attorney General makes the appointments. The Executive Secretary of the commission is authorized to carry out ministerial functions until the fully-authorized membership has been appointed. The new commissioner appointments do not need confirmation by the Senate.

- The commission appointments are required to be broadly representative of the geographic and demographic diversity of the State.

- A member of the commission is not required to recuse himself or herself from any matter before the commission under the legislation on account of prior involvement in the matter in another capacity.

Office of People's Counsel
(Section 1: Section 2-202; Section 13 and 14)

- The People's Counsel is appointed by the Attorney General (rather than the Governor) and confirmed by the Senate. The office maintains autonomous structure.

- The People's Counsel serving as of June 30, 2006, shall continue to serve at the pleasure of the Attorney General until a successor is appointed.

- The term of office for the People's Counsel is five years; at the end of a term, the current People's Counsel serves until a new appointment is made.

- A People's Counsel may be removed by the Attorney General for good cause.

- The People's Counsel is not required to recuse himself or herself from any matter before the commission under the legislation on account of prior involvement in the matter in another capacity.

Standard Offer Service (SOS)
(Section 1: Section 7-510; Section 7; Section 20)

- An electric company continues to have the obligation to provide SOS to residential and small commercial customers after July 1, 2003.

- Obligation is at a market price that permits recovery of verifiable, prudently incurred costs of procuring or producing the electricity plus a reasonable return.

- The commission is no longer required to make a finding concerning whether the electricity supply market is competitive; instead, the commission is required to report every five years (beginning December 31, 2008) on the status of SOS, the development of competition, and the transition of SOS to a default service.

- The commission is required to establish the definition of default service.

- An electric company participating in SOS is required to obtain its electricity supply through a competitive process that is designed to obtain the best price in light of market conditions and need to protect customers from excessive price increases.
  - The competitive process is to include a series of competitive wholesale bids in which the electric company solicits bids for its SOS load as part of a portfolio of blended wholesale supply contracts of short, medium, and long terms as needed to meet demand in a cost-effective manner.
  - The competitive process may include different bidding structures and mechanisms for base load, peak load, and very short-term procurement.
  - To prevent an excessive amount of load being exposed to upward price risks and volatility, the commission may stagger the competitive wholesale auction dates and may allow a date to be altered based on market conditions.

- By regulation or order, the commission may allow an electric company to refuse to accept some or all of the bids made in a competitive wholesale auction.
- The electric company is required to publicly disclose the names of all bidders and the names and load allocation of all successful bidders 90 days after all contracts for supply are executed.

- After completion of a study (due December 31, 2006) which finds the following to be in the public interest, the commission:
  - may require or allow an electric company to procure electricity for SOS customers directly from an electricity supplier through one or more bilateral contracts outside the competitive process;
  - shall require or allow an electric company to procure cost-effective energy efficiency and conservation measures with projected and verified energy savings to offset anticipated demand to be served by SOS, and the imposition of other cost-effective demand-side management programs (after consideration, by December 31, 2006, the commission must establish, by regulation or order, the process to secure bids and criteria to evaluate bids); and
  - may allow an electric company to construct, acquire, or lease generating and transmission facilities, with appropriate cost recovery.

- To protect residential customers from the impact of sudden and significant increases in total electric rates of 20 percent or more, the commission is required to hold proceedings to determine an appropriate phased implementation of electricity rates.

- A deferral of costs as part of a phased implementation plan is required to be treated as a regulatory asset to be recovered in accordance with a rate stabilization plan or any other plan for phased implementation approved by the commission. Deferred costs must be just, reasonable, and in the public interest.

- The recovery of deferred costs may be either long term (in accordance with a rate stabilization plan) or short term (through a rate proceeding).

- A phase-in of increased costs may include placing a cap on rates and allowing recovery over time or allowing rates to increase and providing for a rebate for excess costs paid.

- An electric company is allowed to recover the costs of electricity for which it has contracted before the effective date of this Act to provide SOS.

Electric Cooperatives: Rate Mitigation (Allegheny)
(Section 1: Section 7-510)

- The commission, on request by an electric cooperative or on its own initiative, is required to initiate a proceeding to investigate options for a rate stabilization plan to assist residential electric customers to gradually adjust to market rates over an extended period of time.

- If a cooperative determines that total electric rates for residential customers are anticipated to increase by more than 20 percent (resulting from an increase in generation costs) in a 12-month period, the cooperative is required to survey its membership to determine whether to make a request to the commission.

Electric Universal Service Program (EUSP)
(Section 1: Section 7-512.1)

- The pool of applicants eligible for EUSP is expanded to include those at or below 175 percent of the federal poverty level, instead of at or below 150 percent of the federal poverty level.

- As determined by the Office of Home Energy Programs, bill assistance payments to an electric company may be on a monthly basis for each customer.

- The total amount of funds collected for EUSP each year is raised from $34 to $37 million, with the industrial and commercial classes paying the additional amount.

- An estimated additional $6 million will go to EUSP for fiscal 2007 only from the repeal of a credit that a public utility currently may claim against the State income tax (credit is based on an amount equal to 60 percent of the total property taxes paid by the public utility on its operating real property in the State that is used to generate electricity for sale).

Securitization (General Provisions)
(Section 1: Sections 7-520 to 7-544)

- An electric company may file a rate stabilization plan with the commission which may include both short-term and long-term deferrals of incremental expenses of electricity supplies.

- The rate stabilization plan may provide that a deferral is to be securitized through the issuance of rate stabilization bonds authorized by a qualified rate order approved by the commission.

- Residential customers are charged the full cost of the SOS necessary to recover the electric company's costs, with any credits or charges included as nonbypassable credits or charges on the electric distribution portion of the customers' bills.

- The commission may authorize an electric company to recover, as additional rate stabilization costs, the actual cost to the electric company of carrying the deferred expenses as regulatory assets.

- The commission is required to adopt the qualified rate order if the commission finds that the total amount of revenue to be collected under the order is less than the rate stabilization revenue that would be recovered over the same period using the electric company's weighted average cost of capital.

- The recovery period for the rate stabilization plan may not exceed 12 years.

- After becoming effective, a qualified rate order and the rate stabilization charges may not be altered by further action of the commission, except to reconcile overcollections or undercollections.

- A rate stabilization bond is not a debt, liability, or pledge of the full faith and credit of the State or any other governmental unit.

Rate Stabilization (Specific to BGE)
(Section 1: Sections 7-547 to 7-549)

- An electric company that has an obligation to provide SOS to residential customers for whom rate caps expire at the end of June 30, 2006, is required to file tariffs with the commission to implement a rate stabilization plan.

- The commission is required to order the electric company to establish regulatory assets for the rate stabilization plan of the deferral of the SOS rate deferred during the deferral period beginning July 1, 2006 (for 11 months).

- Any credit or charges to the cost of SOS is required to be included as a nonbypassable credit or charge on the electric distribution portion of the bill for residential customers.

- An electric company may apply to the commission for a qualified rate order for the financing and recovery of its rate stabilization costs.

- The increase in the total rates charged to ALL residential electric customers on SOS, as compared to the total rates in effect on June 30, 2006, **is limited to 15 percent from July 1, 2006, through May 31, 2007** (no opting in or out).

- **On June 1, 2007, consumers have the option to go to market or opt-in** to a short-term intermediate rate stabilization plan (without adversely affecting the creditworthiness of the electric company) until the customers are required to go to **market rates by January 1, 2008.**

- A rate stabilization cost (deferral) may not begin to be recovered before **January 1, 2007.**

- The amount of the deferral is a rate stabilization cost which is to be recovered as a regulatory asset. The commission determines the rate stabilization plan for this recovery.

- An electric company is required to recover, as an additional rate stabilization cost, the actual cost to the electric company of carrying the costs and expenses deferred as regulatory assets under the rate stabilization plan.

Recovery of a Deferral of Electric Costs in a Rate Stabilization Plan (BGE)
(Section 5)

- The commission is required to incorporate into a rate stabilization plan for residential customers of BGE for mitigation of rate increases to include:
  - any adjustment, in favor of customers, to allowances for stranded costs for assets that were transferred from BGE to an affiliate;
  - any funds identified by the commission as properly allocated to BGE and ratepayers as conditions of approval of merger of Constellation Energy, Inc. and FPL Group, Inc.;
  - any taxes collected or voluntary contributions made in lieu of taxes identified under this legislation;
  - the credits shall be in the form of a nonbypassable credit on the electric distribution portion of the customers' bill; and
  - the credits may not be recovered subsequently in rates or otherwise.

Credits to Electric Costs – Nuclear Decommission Charge and Rate of Return
(Section 6)

- Credits are not contingent on the merger. They are used to decrease rates.

- The credits shall be in the form of a nonbypassable credit on the electric distribution portion of the customers' bill or a suspension of a charge, derived as follows:
  - for a period of 10 years, the electric company shall suspend the collection of the residential return component of the administrative charge collected by the electric company for providing SOS, which shall be deemed a value of $20 million annually; and
  - for a period of 10 years, a credit of the $18,661,980 annual nuclear decommissioning charge collected, without otherwise disturbing the agreement approved by the Maryland Public Service Commission in Order No. 75757, to be imputed as deposits in the Nuclear Decommissioning Trust Fund and to be credited against residential electric customer bills. (The nuclear decommissioning charge may not be altered during the 10-year period of the credit.)

- The credits may not be recovered through electric rates.

Income Tax Credit on Real Property Used to Generate Electricity
(Section 2: Section 10-712; Section 10; Section 23)

- The credit that a public utility may claim against the State income tax in an amount equal to 60 percent of the total property taxes paid by the public utility on its operating real property in the State that is used to generate electricity for sale is REPEALED. (Amount is estimated at $6 million.) The Comptroller is required to distribute these funds to the EUSP.

- This provision applies to taxable years beginning after December 31, 2005.

Purchase of Stock of a Public Service Company, Issuance of Stock by a Public Service Company, Lending by a Public Service Company to an Affiliate, and Acquisition of a Public Service Company

(Section 3: Sections 5-104, 5-203, 6-101, 6-102, 6-103, and 6-105; Section 21; Section 24)

Purchase of Stock of a Public Service Company, Issuance of Stock by a Public Service Company, Lending by a Public Service Company to an Affiliate

- Without prior authorization of the commission:
  - a public service company may not purchase/acquire/take/hold any part of capital stock of another public service company that operates in Maryland (currently, approval is only required for companies that are incorporated in Maryland);
  - a public service company that operates in Maryland (currently, refers to incorporated in Maryland) may not issue stocks or bonds (the commission shall take action on an application for authorization within a reasonable time.);
  - a public service company that operates in Maryland may not lend money to an affiliate at rates or on terms that are significantly more favorable to the affiliate than the rates or terms that are otherwise commercially available to the affiliate;
  - a public service company may not take/hold/acquire stock of a public service company that operates in Maryland and is of the same class (currently, refers to incorporated in Maryland); and
  - a stock corporation (unless a public service company of the same class) may not take/hold/acquire more than 10 percent of the total capital stock of a public service company that operates in Maryland (currently, refers to incorporated in Maryland) this provision is construed to apply only prospectively.

- This provision takes effect June 1, 2007.

Person Acquiring Substantial Influence Over Electric Company (if person would become affiliate of the electric company as a result of the acquisition)

- Without prior authorization of the commission, a person may not acquire, directly or indirectly, the power to exercise any substantial influence over the policies and actions of an electric company or gas company that operates in Maryland, if the person would become an affiliate of the electric company or gas company as a result of the acquisition.

- The commission is required to consider the following factors: impact on rates and the continuing investment needs for the maintenance of infrastructure; capital structure that will result; potential effect on employment; projected allocation of savings expected to the public service company between stockholders and ratepayers; issues of reliability and quality of service; potential impact on community investment; affiliate and cross-subsidization issues, etc.

  - The commission is required to issue an order granting the application if the commission finds that the acquisition is consistent with the public interest, convenience, and necessity, including benefits and no harm to consumers.
  - The commission may condition an order on the applicant's satisfactory performance or adherence to specific requirements.

- This provision takes effect January 1, 2007.

Merger of FPL Group, Inc. and Constellation Energy Group, Inc.
(Section 4; Section 5(a) and (b)(3))

- Any approval by the commission of a merger between FPL Group and Constellation Energy Group must have the following conditions:
  - the merger transaction may not provide for the transfer of facilities between FPL or BGE and an associate company;
  - the merger transaction may not provide for the new issuances of securities by FPL or BGE for the benefit of an associate company;
  - the merger transaction may not provide for new pledges or encumbrances of assets of FPL or BGE for the benefit of an associate company;
  - the merger transaction may not provide for new affiliate contracts between nonutility associate companies and FPL or BGE (other than goods and services); and
  - any savings realized must be applied in part to the elimination of carrying charges and the delay of increases in residential electric rates in a plan for rate stabilization.

- The commission may not take final action to approve or disapprove the merger until the new five members are appointed.

- The commission is required to review the proposed merger promptly and comprehensively and take action in accordance with provisions of the legislation.

Proceedings by Public Service Commission
(Section 7; Section 11; Section 18)

- An additional fiscal 2007 appropriation for the commission of $750,000 and for the People's Counsel of $500,000. Costs recovered through the annual assessment on public utilities.

Reevaluate Settlement Agreements

- The commission is required to conduct investigatory and evidentiary proceedings to reevaluate the general structure, agreements, and actions of the previous commissions as they relate to the electric restructuring law, including the determination of and allowances for stranded costs.

- The report is due June 30, 2007.

- The commission may hire experts and consultants.

Study Changes to the Current SOS Process

- The commission is required to initiate an evidentiary proceeding to study and evaluate the status of electric restructuring in the State as it pertains to the availability of competitive generation for residential and small commercial customers.

- The study shall consider changes that are necessary to provide residents the benefit of a reliable electric system at the best possible price and options for reregulation, if advisable and to allow electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility.

- The commission shall give consideration to:
  - allowing investor-owned electric companies to buy power on a long-term contract;
  - allowing investor-owned electric companies to construct, acquire, or lease peak load and other plants;
  - requiring a process at the time of SOS bidding for the procurement of energy efficiency and conservation measures and services (after consideration, by December 31, 2006, the commission must establish, by regulation or order, the process to secure bids and criteria to evaluate bids); and
  - providing a process to allow investor-owned electric companies to obtain a portion of SOS load through bilateral contracts (outside of competitive wholesale auctions).

- The report is due December 31, 2006.

- The commission has authority to implement the above after completing the study and making a finding that they are in the interest of ratepayers.

Study of Small Commercial Customers on SOS

- As part of the review of electric restructuring as it pertains to the availability of competitive generation, the commission is required to adopt a uniform definition of "small commercial" customer.

- Further, the commission shall consider whether it benefits small commercial customers for an electric company not to be required to provide SOS for small commercial customer.

- The report is due December 31, 2006.

Study of Opt-out Local Government Aggregation

- The commission is required to study opt-out local government aggregation in service territories of investor-owned electric companies.

- This study does not interfere with the implementation of a pilot program that the commission is currently working on with the Maryland Municipal League.

- The report on the study is due by December 31, 2006.

- The commission may not implement opt-out aggregation without legislative approval.

Impact of the Costs of Rising Fuel Prices on Low-income Residents

- The commission is required to study the impact of the costs of rising fuel prices on low- and middle-income customers by obtaining information on residential utility turn-off notices issued, actual turn-offs, and reconnections, and amount of arrearages. Reports are due October 1 of each year from 2006 to 2010.

- The commission is required to study (using university-based research) energy affordability programs, including percentage of income plans and tiered rate structure plans. The report is due December 31, 2006.

Allegheny: Rate Mitigation and Renegotiation of Settlement Agreement
(Section 8)

- The commission, on its own initiative or on request of an electric company in the service territory of which a rate cap expires after July 1, 2006, shall initiate a proceeding to investigate options available to implement a rate mitigation plan or rate stabilization plan.

- The commission is required to conduct a proceeding regarding the impact of renegotiation of a settlement agreement to allow a portion of the residential electric supply in that service territory to be procured at market rates earlier than otherwise provided in the settlement agreement so that its full load is not exposed to volatile market conditions at one time, while ensuring that residential customers in that service territory obtain the full value of the savings provided under the existing rate cap.

Pepco and Delmarva: Rate Mitigation
(Section 20)

- This paragraph applies to an investor-owned electric company in a service territory in which a rate cap or freeze is no longer in effect and which has a rate mitigation plan in effect on July 1, 2006, for residential customers, in accordance with an order of the commission.

- The commission is required, through the modification of an existing order on a rate mitigation plan in effect on July 1, 2006 (Pepco and Delmarva), for residential customers to provide an additional time period for customers to opt-in after July 1, 2006.

- The electric company may continue to collect an authorized reasonable return, except that the electric company shall apply the return revenue to any actual carrying charges that the electric company may incur as a result of the deferred amounts from customers who have opted in to the plan.

- If the participation rate of the number of customers who have opted in to the plan is less than 25 percent of the total residential customers of the electric company, the commission shall require the electric company to apply a portion of the return revenue to reducing rates.

- The total amount of return that the electric company is required to apply to reduce rates is the amount by which the total dollar amount of carrying chares that would have been paid if 25 percent of the customers had participated in the plan during the deferral period exceeds the carrying charges actually paid.

Study of the Valuation of Power Plants
(Section 9; Section 18)

- The State Department of Assessments and Taxation is required to study whether the current valuation of power plants provides an adequate determination of the value of power plants in a restructured electric industry.

- The department is required to hire a consultant with expertise in plant valuation.

- The department may not change the current method before May 1, 2007.

- The report is due December 31, 2006.

- An additional appropriation of $250,000. Costs recovered through the annual assessment on public utilities.

Attorney General Intervenes in FPL-CEG Merger Proceedings
(Section 15, Section 18)

- The Attorney General is directed to intervene and participate in commission proceedings and other appropriate State or federal hearings regarding the FPL-CEG Merger.

- Costs and expenses may not exceed $500,000 to be borne by public service companies in the same manner these companies are assessed annually.

Effect of Legislation on Prior Transactions and Actions
(Sections 16 and 17)

- All commission transactions affected from statutes amended in the legislation remain valid, except as expressly provided to the contrary under this legislation.

- All actions of the commission and Office of People's Counsel continue until changed pursuant to law.

Court Action
(Section 19 and 22)

- If any action is brought to challenge the constitutionality of any provision of this legislation:
  - The action must be filed in the Circuit Court of Baltimore City.
  - The Attorney General shall be permitted to intervene.
  - A final decision of the circuit court must be reviewable by appeal directly to the Court of Appeals of Maryland.
  - It is the duty of the circuit court and Court of Appeals to advance on the docket and to expedite the disposition of the action and the appeal.

- The provisions of the legislation are severable.

Emergency Bill
(Section 25)

Source: Chapter 5, Special Session 2006