PUBLIC SERVICE COMMISSION
OF MARYLAND

TEN-YEAR PLAN
(2000 - 2009)
OF
MARYLAND ELECTRIC UTILITIES

Prepared for the
Maryland Department of Natural Resources
In compliance with Section 7-201(a)
of the Maryland Public Utility Companies Article
December 2000

TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

Appendix

I. EXECUTIVE SUMMARY

This report constitutes the Public Service Commission's 2000 Ten Year Plan (2000-2009) of electric utilities operating in Maryland. The Ten-Year Plan Report is submitted annually by the Public Service Commission (Commission), to the Secretary of the Department of Natural Resources, in compliance with Section 7-201(a) of the Public Utilities Companies Article. It is a compilation of information pertaining to the long-range plans of Maryland's electric utilities. An additional feature this year is summaries of issues that may affect the electric utility industry in Maryland in the future.

Section II summarizes the Maryland act that restructured its electric utility industry and gives an update on the competitive activities and generation activity in Maryland under the restructured regulatory regime. Section III provides information on transmission and distribution services in Maryland and the status of recent related Commission orders.

Section IV consists of five subsections. Subsection A summarizes three important orders issued by the Federal Energy Regulatory Commission (FERC) which significantly changes the wholesale power markets in the nation. While these changes are at the federal and regional levels, they do affect the availability and price of electricity at the retail level due to restructuring at the state-level. Therefore, Subsection B summarizes major changes currently underway in the states within the Mid-Atlantic region. Subsection C then covers a very important aspect of the electric utility industry in the Mid-Atlantic region, namely that of the PJM Interconnection, L.L.C. (PJM), the Independent System Operator (ISO). In this subsection, there is a summary of PJM's planning process, its pricing mechanism, its market monitoring activities, and inter-regional cooperation with other ISOs in northeastern U.S. Finally, Subsection D describes events that happened during the past summer in California (in general) and San Diego (in particular). These events were widely reported and followed in the trade press. California being the first state to restructure its electric utility industry, there have been concerns raised in other parts of the nation if similar events could occur elsewhere. That is why the Commission believes inclusion of this information should be pertinent to policymakers in Maryland.

Section V provides a summary of utility efforts to implement demand-side management programs. It summarizes efforts by utilities to promote of energy conservation programs. It provides forecasts for capacity and energy savings for programs through 2013. Finally, Section V provides summaries of utility efforts to promote and utilize renewable resources and cogeneration.

II. RETAIL CUSTOMER CHOICE IN MARYLAND

A. The Maryland Act

In April 1999, Governor Parris Glendening signed Maryland's Electric Customer Choice and Competition Act (Act) into law. This law established the legal framework for the restructuring and regulation of the electric utility industry in Maryland. The Act deregulates "the generation, supply, and pricing of electricity", with the initial sign-up by customers for choice of electric suppliers as April 2000 with service beginning July 1, 2000. The Act provides that retail electric choice will be fully available to all customers by July 2002.

B. Status of Retail Choice in Maryland

On July 1, 2000, all retail electric customers in the State of Maryland were given the opportunity to choose their electric supplier. In the restructured marketplace, if customers choose to remain with their distribution utility, the utility companies will continue to offer Standard Offer Service for a period of not less than four years. Standard Offer Service rates are on average 6.5 percent lower than those in effect prior to electric restructuring for residential customers. A customer may save more money by switching to an alternative supplier. Customer choice holds the potential for new products and services from competitive electricity suppliers.

Unfortunately, customer choice in Maryland begun at a time when energy prices were volatile due to high peak loads and customer uncertainty about choice because of well-publicized problems with California's retail choice programs. As shown in Table 2.1, electricity choice is off to a slow start, with less than 9,000 accounts (or 1% of the peak load obligation) served by licensed electricity suppliers. Although over 30 suppliers are licensed to do business in Maryland, many suppliers are choosing to wait to enter the marketplace due to the uncertainty of summer pricing and publicity surrounding the California experience. A related issue is that of rising natural gas prices which has increased the cost of incremental electricity generation. As additional generation comes on-line within the region, more competition should develop. The Commission will continue to monitor the status of retail choice in Maryland as it develops.

Commission Order No. 75608, issued September 10, 1999 in Case No. 8738, approved the procedures developed by the Supplier Authorization Working Group to license electric suppliers or electric generation service providers in Maryland pursuant to §7-507 of the Public Utility Companies Article of the Annotated Code of Maryland. The licensing process approved by the Commission requires an applicant to provide proof of:

(1) technical and managerial competence;
(2) compliance with applicable requirements of FERC, and any ISO or transmission operator to be used;
(3) compliance with applicable federal and state environmental laws and regulations that relate to the generation of electricity; and,
(4) financial integrity and qualification to do business in the State of Maryland.

To date, the Commission has granted 33 licenses for suppliers and brokers to operate in the service territories served by BGE, Conectiv, PEPCO and Allegheny Power. The following table illustrates the extent to which customers have switched to an electricity supplier.

Table 1: Competitive Activity in Maryland (as of November 24, 2000)

	Number of Suppliers		**Accounts Served by Electric Suppliers**			**Peak Load Obligation Served by Electric Suppliers**		
Distribution Utility	*Resi-dential*	*Non-Resi-dential*	*Resi-dential*	*Non-Resi-dential*	*Total*	*Resi-dential*	*Non-Resi-dential*	*Total*
Allegheny Power	0	2	0	36	36	0.0%	0.4%	0.2%
Baltimore Gas and Electric	1	3	2	163	165	0.0%	0.5%	0.3%
Conectiv Power Delivery	0	5	0	30	30	0.0%	3.5%	1.6%
Potomac Electric Power	N/A	3	6,599	1,983	8582	1.1%	4.2%	2.7%
Total			**6,601**	**2,212**	**8,813**	**0.3%**	**1.6%**	**1.0%**

C. Measuring Competition and Evidence of Anti-Competitive Conduct

Section 7-505 of the Maryland Public Utility Companies Article requires the Commission to facilitate the creation of competitive electricity supply and electricity supply services markets while ensuring the best interests of the customer are met. Commission Order No. 76292, issued July 1, 2000, [1] includes affiliate rules related to promotional practices and standards of conduct for regulated gas and electric companies. Following the issuance of the Commission order, appeals were filed by several of the regulated gas and electric companies that are currently under review in the courts. To date, the Commission has established the dockets for individual company reviews to the extent not precluded by the Circuit Court order.

D. Generation Activity in Maryland

Maryland has seen a significant increase in the number of proposed generation projects seeking Certificates of Public Convenience and Necessity from the Public Service Commission. As Maryland moves forward to a competitive electricity market, developers are proposing new plants to meet the increased demand for electricity.

The following table identifies planned facilities expected to be located in Maryland now being reviewed by the Commission:

[1] Order No. 76292, Case No. 8820, *In the Matter of the Investigation into Affiliate Activities, Promotional Practices and Codes of Conduct of Regulated Gas and Electric Companies* (July 1, 2000).

Table 2: Maryland Generating Facilities under Review

Plant (Applicant)	Capacity (MW)	Location	Expected In-Service Date
Inner Harbor (Trigen Cinergy Solutions)	2.1	Inner Harbor East Central Energy Plant Baltimore	Early 2001
Cogeneration Facility University of MD-College Park (Trigen Cinergy Solutions)	27.3	Central Steam Plant College Park	2001
Brown Station Road Landfill	4.2	Prince George's County	2001
Allen Foods	4.0	Hurlock Processing Plant Dorchester County	2001
Sweetheart Cup	11.5	Ownings Mills	2001
Cecil County (Reliant Energy/Old Dominion Electric Cooperative)	1,100.0	Western Cecil County near Rock Springs	May 2002
Kelson Ridge (Columbia Electric Corporation)	1,650.0	Kelson Ridge Facility Piney Reach Business Park, Charles County	January 2003

Trigen Inner Harbor East, LLC

Trigen Inner Harbor East, LLC is constructing a 2.1 MW gas-fired peak-shaving generator. This generator will be located at the Inner Harbor East Central Energy Plant in Baltimore City, Maryland. The 2.1 MW gas-fired peaking facility will provide electricity for use by the Inner Harbor East Complex during the peak usage season (summer cooling period). Annual operations for the peaking unit are expected to be limited to 87 million cubic feet of natural gas per year on a monthly rolling basis. The tentative facility in-service date is early 2001.

Cogeneration Facility at University of Maryland – College Park

The University of Maryland College Park (UMCP) has contracted with Trigen Cinergy Solutions to install and operate a 27 MW combined heat and power plant at University of Maryland College Park (UMCP). The objective of the project is to ensure reliable generation and distribution of both electricity and steam throughout the campus. The system replaces two existing systems now in operation at the UMCP boiler house. The project expects to use all of the steam and electricity produced within the facility. The project will not be connected to the grid for sales outside of UMCP. The tentative facility in-service date is 2001.

Brown Station Road Landfill

Prince George's County has proposed to install new generators at the Brown Station Road landfill, near Upper Marlboro, Maryland, to burn methane generated from decaying waste. The county plans to install additional gas extraction wells to fire the new generators for use at a nearby correctional facility to provide electricity for prison needs. The tentative facility in-service date is 2001.

Allen Family Foods, Inc.

Allen Family Foods, Inc. in conjunction with CHx Engineering are proposing to construct a 4 MW electric generating station. This station will use poultry litter from company-owned farms and contract growers as fuel and be located at the Hurlock Processing Plant in Dorchester County, Maryland. The 4 MW facility will gasify the poultry litter at low temperatures, collect the solids for commercial fertilizer, destroy the odors at high temperature and indirectly transfer the heat from the processes to produce steam and power for the Allen Hurlock Processing Plant. Surplus electricity produced by the station will be sold to the power grid. The tentative facility in-service date is 2001.

Sweetheart Holdings, Incorporated

Sweetheart Holdings, Incorporated is proposing to construct an 11.5 MW gas-fired generator. This generator will be located at the Sweetheart Cup Facility in Owings Mills, Maryland. The proposed facility, an 11.5 MW gas-fired combined heat and power plant cogeneration unit, will repower the facility's steam generating capacity currently supplied by three existing boilers. The cogeneration unit will consist of two internal combustion engines with duct burners providing supplemental firing in the heat recovery steam generators. The cogeneration unit will utilize selective catalytic reduction technology to control nitrogen oxide (NO_x) emissions from the engines and an oxidation catalyst to control emissions of carbon monoxide (CO) and volatile organic compounds (VOC) from the engines. The tentative facility in-service date is 2001.

Combustion Turbine Facility in Cecil County

Old Dominion Electric Cooperative (ODEC) has proposed to construct a 1,100 megawatt (MW) gas–fired peaking facility near Rock Springs, Maryland. The site is located on the Pennsylvania border and includes 93 acres in Maryland and about 16 acres in Lancaster County, Pennsylvania. ODEC's partner in the venture is Reliant Energy of Houston, Texas. The proposed plant is expected to serve three of ODEC's member distribution cooperative's capacity in the Delmarva Peninsula; Choptank Electric Cooperative, Delaware Electric Cooperative, and A&N Electric Cooperative. A portion of the output will also be sold back into the transmission grid to regional customers. The plant's natural gas fuel will be delivered via a Columbia Gas Pipeline crossing the site. The expected in–service date for the plant is May 2002.

Gas – Fired Combined Cycle Plant in Charles County

Columbia Electric Corporation has proposed to build a 1,650 MW facility near St. Charles in Charles County, Maryland. A Columbia Gas pipeline running to the west of the site will deliver the plant's natural gas fuel. The plant includes a steam cycle to increase efficiency and, because of this, there will also be the need for a cooling system to condense the steam exiting the turbines. The cooling system may include treated effluent from the Mattawoman Sewage Treatment Facility as cooling water, or installation of air–cooled condensers. The tentative facility in-service date is January 2003.

III. TRANSMISSION AND DISTRIBUTION (UTILITY) SERVICES

A critical issue related to electric utility restructuring concerns system reliability. The Commission has historically had a mandate to ensure safe reliable utility service throughout Maryland. This obligation was provided by the Public Utility Companies Article and reaffirmed in the Electric Customer Choice and Competition Act of 1999 (§7-505 (a)). As a consequence of electric utility restructuring, the Commission will no longer have statutory responsibility for the oversight of generation facilities, but the Commission will continue its ongoing review of the maintenance and operation of electric utility transmission and distribution facilities in the State. The Commission requires that electric distribution companies will continue to invest in appropriate mitigation or expansion measures to ensure the reliability of their delivery systems.

All licensed electric suppliers must enter into service agreements (e.g. supplier coordination agreement, EDI trading partner agreement) with the distribution utilities. The supplier coordination agreement acknowledges that the licensed electric supplier has read and understands the utility tariffs and will comply with the terms and conditions contained in the tariffs to ensure delivery of supply.

A. Distributed generation

Distributed generation targets placement of generation or load reductions to defer capital investments in distribution or transmission equipment or to alleviate transmission constraints that result in higher costs for transmission service. Some distributed generation resources are the result of cogeneration by organizations other than electric companies.

The PJM Members' Committee formed the PJM Distributed Generation User Group (DGUG) in response to the FERC May 17, 2000 order supporting reliability initiatives for the summer of 2000. The purpose behind formation of the group was the development of a process by which distributed resources could be utilized in support of reliable operations over this peak summer period. To this end, the DGUG developed and implemented the PJM Customer Load Reduction Pilot Program. This program represented a consensus of the User Group, and was approved by the PJM membership.

Following this year's summer period, the DGUG expects to incorporate all possible distributed resources into PJM markets and operations whether generation or load. For the summer 2000, the DGUG objectives included utilizing the experience gained from the summer 2000 Customer Load Reduction Pilot Program, to develop and propose implementation of a new program that represents consensus of the DGUG to the appropriate PJM committees for long-term implementation beginning in summer 2001.

PJM's tariff includes a streamlined interconnection request process for generation resources less than 10 MW. The streamlined process waives $60,000 in fees that are required for generation resources over 10 MW. Also, the power flow modeling, required to assess the generation resource impact on reliability and stability, is typically done by the electric distribution company. Interconnection manuals are being developed by several Maryland

electric distribution companies. The publication of these manuals will provide valuable information to potential distributed generation developers.

B. New Standards Adopted (Case No. 8826)

On October 1, 1999, the Commission docketed Case Number 8826, Investigation Into the Preparedness of Maryland Utilities for Responding to Major Outages. After hearings were held in this matter, the Commission issued Order 75823 on December 9, 1999. Therein, the Commission directed electric utilities, Staff, OPC and other interested parties to evaluate whether the development of operation and performance standards for electric utilities would enhance reliability and/or mitigate the effects of storm and disaster related outages. All interested parties met on December 22, 1999 to establish working groups to provide the reports directed by the Commission in Order 75823.

In order to satisfy the Operation Standards portion of the directive, the group initiated discussions on the operation and maintenance programs of the electric utilities. In order to satisfy the Performance Standards portion of the directive, the group initiated discussions about the reliability indices that can be calculated to quantify the performance of electric systems. The Electric Utility Reporting Standards Working Group provided a final report to the Commission on February 7, 2000. The Operation and Performance Standards Working Group presented a final report to the Commission on April 25, 2000. The Commission is expected to issue an order on the working group reports.

C. Undergrounding (Case No. 8826)

On February 14, 2000, the Selective Undergrounding Working Group (Working Group) filed a report with the Commission evaluating the feasibility of selectively undergrounding segments of utility transmission and distribution systems as a possible means of limiting the frequency or duration of electric power outages. This work was performed at the direction of the Maryland Public Service Commission pursuant to Order No. 75823, which was issued on December 9, 1999 in Case No. 8826, "In the Matter of the Investigation into the Preparedness of the Maryland Utilities for Responding to Major Outages."

The Working Group recommended that the utilities continue to underground electrical and other facilities under the same circumstances as presently occurs. Specifically, these circumstances include, as mandated by COMAR 20.85.01 – 20.85.05,[2] at the customer's request or as appropriate for reliability reasons. The Working Group also recognized, however, that with the improvement of available technology, the installation and long-term operation and maintenance costs of underground electric facilities may decline, while their durability and other operating characteristics may improve. Such changes in the state of the industry may make the selective undergrounding of electrical power facilities a more cost effective and viable means of improving service reliability to customers in the future.

[2] These COMAR provisions require undergrounding of extensions of electrical distribution lines necessary to furnish permanent electric service to new commercial and industrial buildings, multiple-occupancy buildings and new residential buildings.

Further, the Working Group recommended that when other reliability initiatives fail and undergrounding is necessary to improve service, utilities should keep detailed cost and operation information concerning the subject line section over the service life of the underground project. This information, where available, should include such data as the undergrounding construction costs, reliability data (including both indices and specific causes of outages before and after the undergrounding), customers affected and location in the electrical system. This information could then be reviewed and used as a basis for reevaluating the viability of selective undergrounding for other reliability oriented projects in the future. The Commission is expected to issue an order on the Working Group's report.

IV. RESTRUCTURING OF THE ELECTRIC UTILITY INDUSTRY

A. Important FERC Activities

1. FERC Orders No. 888 & 889

On April 24, 1996, the Federal Energy Regulatory Commission ("FERC") issued Order No. 888 which was "designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers." In issuing this order, the primary goal was "to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce." FERC Order No. 888 required "all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce:

- to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;
- to take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs; and,
- to develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications." (75 FERC 61,080).

In a related action on that same date, FERC, by Order No. 889, promulgated new regulations that contained "rules establishing and governing transmission information networks and standards of conduct." This order applies to any public utility that offers open access transmission services under Order No. 888's open access pro forma tariff, and required each public utility that owns, controls, or operates transmission facilities to develop or participate in an Open Access Same-time Information System (OASIS).

2. FERC Order No. 2000

On December 20, 1999, FERC issued Order No. 2000 that established minimum characteristics and functions for appropriate Regional Transmission Organizations (RTOs). This included "a collaborative process by which public utilities and non-public utilities that own, operate or control interstate transmission facilities, in consultation with state officials as appropriate, will consider and develop RTOs." The FERC believes that "appropriate RTOs could successfully address the existing impediments to efficient grid operation and competition and could consequently benefit consumers through lower electricity rates resulting from a wider choice of services and service providers. In addition, substantial cost savings are likely to result from the formation of RTOs." The FERC's Order established the following criteria for RTOs:

- Minimum Characteristics -- independence, scope and regional configuration, operational authority, and short-term reliability;
- Minimum Functions -- tariff administration and design, congestion management, parallel path flow, ancillary services, OASIS, total and available transmission capability, market monitoring, planning and expansion, and interregional coordination.

B. Regional Statewide Activities [3]

As of November 2000, half of the states in the nation (including D.C.) have enacted restructuring legislation or issued commission orders. In two states, such legislative activity is pending, while there are investigations/studies ongoing in 16 states. There is no activity in eight states. The following is an overview of restructuring activities in other states within this region.

1. Pennsylvania

In December 1996, the Commonwealth of Pennsylvania enacted House Bill 1509, the "Electricity Generation Customer Choice and Competition Act". Customers were allowed to choose among competitive generation suppliers on the following schedule: one-third of the customers on January 1, 1999; another one-third on January 1 2000, and the rest on January 1, 2001. In March 1998, House Bill 2286 accelerated retail choice such that one-third still had choice on January 1, 1999 and the remaining two-thirds had choice by January 1, 2000. Electric utilities in Pennsylvania were also required to submit restructuring plans to the Pennsylvania Public Utility Commission (PAPUC) by September 1997. Over 1.1 million customers enrolled during the first week of eligibility in Pennsylvania's Electric Choice Program. The Pennsylvania Office of Consumer Advocate (PAOCA) reports that an estimated 507,000 consumers have switched to competitive generation suppliers as of January 2000. Additionally, residential customers have the opportunity to choose four (4) "Green-e"[4] products. Residential customers have also received a "How to Shop" guide and a list of competitive generation suppliers.

2. Delaware

On March 31, 1999, Governor Tom Carper signed House Bill No. 10, which restructured Delaware's electric utility industry beginning October 1, 1999. Delaware has one investor-owned electric utility -- Delmarva Power & Light (DP&L) -- and one cooperative -- Delaware Electric Cooperative (DEC). DP&L also serves Maryland and its parent company is Conectiv. DEC is a member of Old Dominion Electric Cooperative (ODEC). One of ODEC's members -- Choptank -- operates in Maryland. Delaware's Act "freezes" rates and phases-in customer choice differently for DP&L and DEC. Only DP&L's residential customers receive a 7.5% rate decrease. Based on the phase-in, all of DP&L and DEC customers will have choice by April 1, 2001. However, all nine municipal utilities in Delaware have the ability to initiate electric choice on their own schedule with a reciprocity arrangement. In the DP&L service territory, there are two public purpose funds collected as part of the distribution rates. These are the environmental incentive fund ($0.000178/kWh each month, approximately $1.5 million annually) and the low-income fund (0.000095/kWh each month, approximately $800,000 annually). There is the provision for a consumer education fund of $250,000 collected from DP&L and DEC apportioned based on 1998 kWh retail sales. In terms of current activity, 18 entities have been certified as Electric Suppliers for the State of Delaware.

---

[3] Source: Energy Information Administration.

[4] A product with the Green-e logo is certified to have been generated from 50% to 100% renewable resources.

3. District of Columbia

In January 2000, the District of Columbia (D.C.) City Council passed legislation to allow retail electric competition. The D.C. Public Service Commission (DCPSC) is reviewing PEPCO's restructuring settlement, under which commercial and government consumers will have retail direct access and residential consumers will begin a retail access pilot by January 2001.

4. West Virginia

In March 2000, the West Virginia (WV) legislature approved the Electricity Restructuring Plan submitted by the WVPSC. The plan allows retail choice by January 2001; unbundles and caps rates until 2004; and provides commercial and industrial rate reductions through 2005. The legislation requires passage of a resolution in the 2001 session before the provisions of the law can go into effect. In October 2000, lawmakers indicated the need to be convinced that restructuring will benefit West Virginia consumers in light of the low cost of electricity in that state and the price spikes experienced during the summer of 2000 in other states that have already restructured their electric industry. Most of the concerns center on protecting small/residential consumers from price increases.

5. Virginia

In March 1999, Virginia enacted its Electric Utility Restructuring Act. Highlights of the bill include the creation of a regional transmission entity by January 2001; deregulation of generation by January 2002; phase-in of consumer choice between January 2002 and January 2004; rates capped through July 2007 for those who remain with the incumbent utility; recovery of stranded costs through capped rates for customers staying with the incumbent utility and through a wires charge for those who switch to competitive suppliers; and consumer protections such as universal service, education programs, fuel and emission disclosure requirements, and allowing aggregation for small consumers. In November 1999, American Electric Power filed, with the Virginia State Corporation Commission, a plan for a pilot program for 2% of its customers. AEP, Virginia Power, and Rappahanock Electric Cooperative indicated in February 2000 that pilot programs should begin before mid-year 2001.

6. New Jersey

In February 1999, New Jersey enacted legislation to restructure its electric power industry. The law allowed all consumers to choose alternate electric suppliers by August 1999; reduced rates by 5% immediately and by 10% over the next three years; and allowed recovery of utilities' stranded costs through a wires charge paid by consumers.

C. Regional Wholesale Issues

1. PJM Planning - Generation

In order for a generator to supply power into the PJM system, it must first submit a request for Generation Interconnection to PJM. The following is a summary of the generation interconnection process in PJM.[5]

Generators or suppliers submit requests for Generation Interconnection. Once requests are submitted, PJM coordinates the performance of feasibility studies. The PJM ISO/RTO develops and completes feasibility studies based on technical/engineering information as well as financial and cost estimates. After a through review, the ISO/RTO provides feasibility study results to individual generators. If the feasibility study comes up unsatisfactory the request for generation interconnection is withdrawn. If the feasibility study shows positive results, PJM will make the project public, request proof of property rights, and release funds for PJM to perform an impact study. Impact studies are performed to evaluate the generation project as part of the entire PJM system. The results of impact studies are made available to generators/suppliers. If the generators do not meet economic feasibility requirements, then the project request is withdrawn. If the impact study shows positive results, then PJM begins providing siting and permitting schedules, releasing fees for facility studies, and preparing interconnection agreements. At this point, generator(s), transmission owner(s), and PJM execute agreements concerning the projects studied. The transmission owner(s) perform facility studies, which are coordinated under the direction of PJM. Once all information gathering (feasibility/impact/ facility studies) has been completed, PJM begins their 6-month review process of current projects that have met all requirements. If the parties meet the requirements of the agreements, construction/place-in-service commences; otherwise the parties begin a dispute resolution process.

PJM has grouped Generation Interconnection requests into queues based on the date the request was made. Table 3.1 shows the actual generation additions for calendar year 2000 and the proposed generation additions for ensuing years. A majority of projects in Queues B–E may be withdrawn by the developer or PJM due to transmission problems or a situation where the generation resource causes a cascading instability problem on the transmission grid. Also, changes to construction schedules may result in changes to the in-service dates.

Table 3: Actual and Proposed Generation (MW) Additions in PJM [6]

Queue	2000	2001	2002	2003	2004	2005	TOTAL
A	348	3,028	7,691	4,184	126	500	15,877
B	168	652	100	500	9,266	0	10,686
C	0	0	5	0	2,888	0	2,893
D	24	3	0	0	0	7,910	7,937
E	0	4	0	0	0	6,081	6,085
F	0	0	0	0	0	650	650
TOTAL	540	3,687	7,796	4,684	12,280	15,141	44,128

[5] Information about the process is from the PJM website (www.pjm.com) and information supplied from TEAC meeting of February 25, 1999.

[6] Information from the PJM website (as of 12/22/00) and PJM Staff.

2. PJM Planning - Transmission

The PJM's Board of Managers, at its August 2000 meeting, approved the Regional Transmission Expansion Plan (RTEP) for the PJM Control group. The plan has the following transmission requirements: (1) mitigates existing "baseline" system reliability criteria violations; and (2) accommodate the interconnection of new generation resources and the increased capacity of existing resources.[7]

The RTEP is comprised of approximately $359.4 million of new transmission construction and upgrades to current facilities. The transmission owners are responsible for $31.9 million of the $359.4 million for facilities related to baseline criteria violations.[8] The remaining $327.5 million are costs that will be paid by the developers of projects in the various Generation Interconnection queues.

Import/Export Capability of PJM

The PJM Interconnection, L.L.C., has determined that its emergency import capability of 3,500 MW (or higher) is considered adequate for the planning year 2000. Long-range forecast (2007), suggest that the emergency capability should be maintained at the 3,500 MW level unless system integrity is compromised or new generation facilities are constructed and brought on-line. Additional forecast suggests that transmission adequacy estimates are solely dependent on the future sites of generation resources. It is imperative that generation owners plan their resources five years in advance in order to allow transmission owners the ability to plan and construct necessary transmission and distribution networks.

According to data from Transfer Capability calculations, it would appear that PJM has substantial transfer capability into the PJM from outside and adjacent systems or power pools. Based on PJM forecasts, summer transfer capability into PJM will be increasing on the paths from the New York Power Pool (NYPP) East and NYPP West and thus decreasing from Western sources and Virginia Power (VP).[9] The winter transfer capability into PJM will have increases in flow from Western sources and VP while flows will decline from NYPP East and West paths.

The transfer capability of PJM to other outside systems or power pools will continue to be relatively good except for the path flow from PJM to the NYPP East. This path flow is considered by PJM to be the one which will have the most limiting capability. Due to transmission congestion the transfer capability between these two paths will have to be reduced. PJM planners believe that this path is susceptible to limited capability due to impending retirements and the uncertainty of possible generation additions located in Northern New Jersey. It should be noted that, according to PJM's transmission assessment report, higher levels of transfer capability are possible between PJM and neighboring systems to the West and South

[7] PJM Interconnection, L.L.C, memorandum/e-mail dated 10/18/00 from Steven R. Herling, General Manager, System Coordination Division, to Transmission Owners Agreement – Administrative Committee.

[8] *Ibid*.

[9] System Coordination Division, PJM Interconnection, L.L.C., *1997-2006 PJM Transmission Adequacy Assessment*, p. 5.

although re-dispatch frequency and cost increase considerably as transfers into PJM from west to south exceeds 4000 MW. [10]

Long-range forecast for transmission capabilities (2007) suggests that where the load is located and the future siting of generation facilities will determine the adequacy of transmission capability. Locating generation near load centers will dramatically reduce the lead-in and construction time for developing proper transmission facilities. As for now, transmission constraints are a possibility due to the need to move power to the economically growing sectors of the State. Until new transmission and generation facilities are developed, PJM believes that the following lines are more sensitive to transmission congestion:

- Doubs-Dickerson (MD) 230 kV (transfers from the West).
- Dickerson-Pleasant (MD) View 230 kV (transfers from South to West).
- Northern PS (NJ) 230 kV facilities (economic imports and transfers to NYPP East).
- Homer City (PA) 345/230 kV transformers (transfers from NYPP West).

PJM Load Projections/Forecast

PJM forecasts suggest that summer peak load will increase at an average annual rate of 1.4% over the next ten year period.[11] Load growth is heavily influenced by the economic growth and development of an area. Economic Forecast suggests that Maryland's economic growth will continue to increase due to the influx of technology and Internet-based companies. This type of economic growth and development will truly impact and probably increase the overall demand for electricity in the state. Maryland's EDCs and EGSs must be cognizant of this increase in commerce in order to handle the future growth of electric load. Maryland is an economically growing state and its electric utilities must be able to provide the electric energy needed for growing business and commerce.

3. Allegheny Power & Establishment of PJM West [12]

Allegheny Power, the energy delivery business of Allegheny Energy, Inc. and PJM announced an agreement to develop a new electric transmission system affiliation. Through this affiliation, PJM will expand its regional scope and demonstrate the ability of its energy market and congestion management systems to function over multiple control areas. Allegheny Power will satisfy the FERC's independence requirement for its transmission system operations while continuing to pursue the development of a large, regional, independent transmission entity.

The affiliation will be known as "PJM West." The new agreement will provide transmission service to all market participants in accordance with FERC Order 2000 while simultaneously expanding the PJM market. The arrangement expands the PJM system beyond a single control area with the potential to result in a significantly larger energy market.

---

[10] System Coordination Division, PJM Interconnection, L.L.C, *1997-2006 PJM Transmission Adequacy Assessment*.

[11] PJM Interconnection, L.L.C., *1997-2006 PJM Transmission Adequacy Assessment*, System Coordination Division, p.7.

[12] Information for this section was provided by the Alleghney Energy Website, News release October 5, 2000.

The current timeline for the agreement includes negotiation for a definitive contract to be completed by February 1, 2001, execution prior to March 1, 2001, and implementation by December 15, 2001. An administrative office would be created and the PJM West Transmission Owners would transfer monitoring and functional control of their transmission systems to PJM.

4. Locational Marginal Pricing (LMP)

The electric industry has experienced large-scale changes over the past several years with the indoctrination of competition in the electric marketplace. These changes require a new way of doing business as a regulated environment takes on the characteristics of a competitive model. One of the most compelling changes relates to the pricing of energy. Under a regulatory structure, energy rates were based on cost of service studies. These studies priced out each individual component of service (generation, transmission and distribution.) With the advent of full competition and the increasing probability of transmission constraints, energy prices will be priced based on a concept called Locational Marginal Pricing or LMP.

LMP is a methodology for pricing energy when there is a transmission constraint or congestion on the electric grid (in this case the PJM system.) In essence, the constraint or congestion price reflects the out-of-merit re-dispatch of generation and the cost to deliver the energy to its desired location (bus). From an economic point of the view, LMP is the marginal (additional) cost of supplying energy to a specific location on the electric grid, taking into consideration generation costs and the physical limitations of the existing transmission grid.[13]

If the transmission system is unconstrained (electric power is free flowing over the transmission grid), then there is a single price for energy. This price is equivalent to the marginal cost of the additional or last unit of demand. The price of energy will be uniform over the entire region or in this case the PJM power pool. Since there is no transmission congestion, the cost of the congestion will be equal to zero.

During times of transmission constraint or congestion, LMP is used to determine the market price based on location. When the transmission system is congested, the marginal cost of energy varies due to its general location. Available low cost generation in various locations on the electric grid may not be able to be delivered to its demand location due to transmission constraints. Generally speaking, LMPs on the consumption side of the constraint are higher than those on the generation side of the congestion. It should be noted that LMP recognizes the locational price differences during a constraint, and thus promotes market efficiencies and disallows any attempts by market participants to shift costs to others

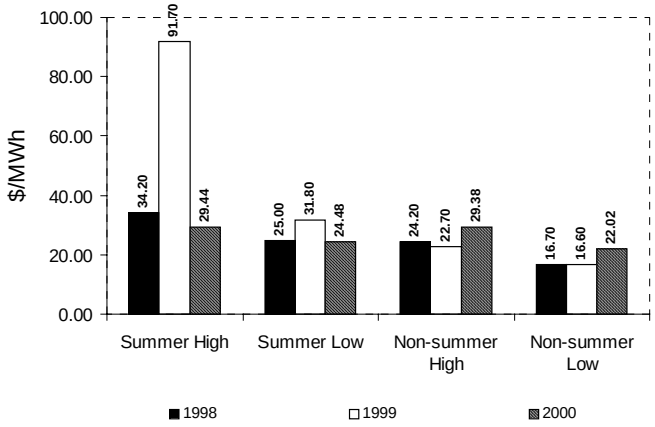
LMP was implemented by the PJM on April 1, 1998. With the approval of the PJM Supporting Companies FERC filing, market-based pricing was instituted on April 1, 1999. The scope of this filing gave generators the ability to bid generation assets on a market-based approach instead of cost-based. Generators could offer market-based prices subject to a PJM established bid cap of $1,000/Mwh. PJM, for the most part, has been a summer peaking entity

[13] Information supplied by PJM during a briefing concerning LMP and the Regional Market Model. Briefing provided by Andrew Ott of PJM and Samuel Thomas of GPU Energy.

and the chart below illustrates the high and low LMPs during summer (June through August) and non-summer months.

Figure 1:

PJM Locational Marginal Prices (LMP)



The data highlights a gleaming fact that prices and their subsequent price dispersions were higher during market-based bidding in the summer of 1999 than those of cost-based bidding in summer 1998. The summer of 1999 did have some extenuating circumstances with 15 days of extreme weather conditions (hot, hazy and humid conditions over consecutive days). Even with the weather events of 1999, the LMP market mechanism produced the necessary price signals to alert generators that additional injections of MWs were needed to alleviate transmission congestion.

5. PJM's Market Monitoring Unit

In November 1997, the FERC approved a filing to authorize PJM as an Independent System Operator (ISO). Within this filing the FERC asserted that "it is important to monitor its implementation to assess undue discrimination and market operation."[14] Furthermore, the FERC directed PJM to develop a market-monitoring plan, which primarily was to ascertain market power abuses. In June 1998, PJM Interconnection, L.L.C., filed its market-monitoring plan with the Commission. In developing this plan, the PJM established a Market Monitoring Unit (MMU) which would monitor market conditions.

The objectives of the MMU are to:

(a) monitor and report on issues relating to the operation of the PJM market, including the determination of transmission congestion costs or the potential of any Market Participant(s) to exercise market power within the PJM Control Area;

(b) evaluate the operation of both pool and bilateral markets to detect either design flaws in the PJM Market operating rules, standards, procedures, or practices as set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, or PJM Regional Practices Document or

[14] PJM Interconnection, L.L.C., Report to the Federal Energy Regulatory Commission, Enforcing Data Requests, Market Monitoring Unit, April 1, 2000, p.1.

to detect structural problems in the PJM Market that may need to be addressed in future filings;

(c) evaluate any proposed enforcement mechanisms that are necessary to assure compliance with pool rules; and,

(d) ensure that the monitoring program will be conducted in an independent and objective manner.[15]

6. Inter-regional Coordination/Cooperation

State Regulators' Coordination with PJM

During August 1998, the Mid-Atlantic Conference of Regulatory Utilities Commissions (MACRUC) and PJM Interconnection signed a Memorandum of Understanding (MOU) to facilitate communication and cooperation among the two organization so as to promote and protect public interest. MACRUC members are commissioners from utility commissions primarily in the PJM control area. While the respective chairs of each commission signed the MOU, each commission retained its right to act independently on any matter, if necessary. Under this MOU, a Liaison Committee was formed, consisting of at least one member of each commission and the PJM Board. Under this Committee, a Staff Sub-committee was to coordinate and advise the Committee in its activities. These members meet regularly to act on issues of mutual interest with the Mid-Atlantic region.

Northeast ISOs

In early August 1999, the presidents of ISO New England, New York ISO, and PJM Interconnection signed a MOU to enhance coordination and activities among the three northeast ISOs. This MOU outlined how the three ISOs will share information and work together to enhance power supply reliability and encourage robust, competitive markets by simplifying transactions and facilitating interregional monitoring. Currently, members of the ISOs are working on issues to facilitate the activities stated in the MOU.

D. California's Experience During the Summer of 2000

During the summer of 2000, California -- and particularly San Diego -- experienced several electricity outages and price increases. This section will compare the electricity market in California with that in Maryland, discuss the incidents in California, and review how the PJM system operates comparatively. The population of California is approximately 7 times that of Maryland while California's electricity usage is approximately 4 times that of Maryland. California is dependent on generation imports from surrounding states to provide up to 20% of their peak demand requirements, while Maryland as part of the PJM marketplace has the required resources within the region to meet peak demand plus a reserve margin. The table below illustrates the number of customers and usage by class for the two states.

[15] PJM Interconnection, L.L.C., website, Market Monitoring Unit Section.

Table 4: Customers and Consumption, California and Maryland, 1999

Number of Customers

Service Territory	Residential	Commercial	Industrial	Total
California	8,843,785	997,859	30,104	9,871,748
Maryland[16]	1,936,389	211,264	7,569	2,155,222

Customer Usage (GWh)

Service Territory	Residential	Commercial	Industrial	Total
California	73,709	86,348	51,915	211,972
Maryland	22,444	25,222	9,733	57,399

1. Conditions in California

California's outages and price spikes are the result of higher than normal temperatures, shortages in supply, transmission constraints and possible "gaming of the system" by suppliers. California has been experiencing above normal temperatures since early summer. On June 14, 2000, temperatures in California reached 103 degrees (35-year weather record) which lead to high electricity demand during peak hours of 43,300 MW system wide. The high loads and short supply of electricity increased the price almost 300% (from 5 cents to 15 cents per kWh). Attachment 1 details specific information on each emergency situation that occurred this summer in California.

Supply shortages that occurred during early June were typical of what has occurred throughout the summer. With tight supplies, outages that are both planned and unplanned have occurred. In early June, supply shortages in the Northwest contributed to the California problems. Bonneville Power Administration called a maintenance outage for hydroelectric facilities located in British Columbia. Further, nine key generating plants were not fully operational either for scheduled maintenance or due to operating at limited capacity. The amount of generation unavailable was 488 MW on June 14, 2000 and increased to 800 MW on June 15, 2000. In the near term, this shortage of supply is expected to continue, since new plants are not expected online until 2002.

A report to the governor from the California Public Utilities Commission (PUC) stated that other causes "such as transmission supply constraints and dysfunctional behavior may have contributed to the price volatility in the wholesale market". Above normal weather conditions in neighboring states have limited California's ability to import electric power. Also, transmission lines in the Bay Area and San Diego (that are the areas where the emergency occurred) are very old with limited lines into the area.

Further it has been reported that "gaming of the system" by suppliers may have occurred to drive the price spikes. In the situation of a tight market, where sellers are certain demand will exceed supply, suppliers may well have been withholding supply anticipating higher prices or

[16] 10-Year Plan, Customers and Usage as of December 31, 1998.

bid prices that did not correspond to their variable costs. There is also a concern that suppliers may have colluded to drive prices higher. These issues are under investigation by the California PUC.

The California ISO ("CA-ISO") Department of Market Analysis has concluded that the recent price spikes are indicative of electric markets that are not "workably competitive" under predictable system conditions. The CA-ISO noted that inelastic demand, barriers to the entry of new suppliers and the lack of significant new generating resources warrant the retention of the price caps in the real-time electric markets to combat market power. The CA-ISO is undergoing a comprehensive market redesign to address flaws in its transmission congestion management system (local market power) and is expanding the scope of its comprehensive market redesign to remedy all market power concerns. The CA-ISO Department of Market Analysis noted that market forces alone cannot remedy the current problems and it is seeking rules, procedures, and incentives to resolve the issues.

2. California's Market Operation

The overall electric market in California is a combination of multiple distinct electric markets mostly operated by the California Power Exchange (CA-PX) and the CA-ISO. The CA-PX administers forward electric markets through wholesale power auctions. The major CA-PX markets include day-ahead and day-of energy markets as well as block forward energy and ancillary service markets. An example of a block forward market is an auction for energy for an entire month at a fixed price. The forward markets offer price certainty as well as a mechanism to hedge against price volatility. The CA-PUC has limited the reliance on block forward markets for at least two of the three major utilities. In June 2000, the CA-PX forward markets represented 64% or nearly $ 2.3 billion of the overall electric market.

In addition to operating the utility-owned transmission facilities, the CA-ISO operates several electric markets including a real-time energy imbalance market and real-time ancillary service markets. In June 2000, the real-time markets represented 21% or nearly $800 million of the over electric market. The remaining or 15% of the overall electric market in California based on June 2000 data is comprised of bilateral contracts and municipal loads. Until this summer, the largest three California electric utilities were required to purchase all of their power through the CA-ISO and CA-PX markets. Only large customers and power marketers were permitted to transact bilaterally, through regional spot markets or other power exchanges.

The CA-ISO operates the system with a watch on operating reserve margins using the Electric Emergency Plan outlined below:

Event	Procedure
Level I – reserve margin below 7%	ISO notifies public of potential shortages and appeals to residential consumers to conserve at home.
Level II – reserve margin below 5%	ISO requests commercial customer "voluntarily" curtail usage
Level III – reserve margin below 1.5%	ISO initiates involuntary curtailments or rolling blackouts

Under the first stage, Level I, which is initiated when operating reserves fall below 7%, the public is advised of potential shortages and asked to initiate conservation efforts at home. This request should not disrupt employment, impede commerce or production. However, if conservation measures do not do enough to lower demand for power, load management programs implementing voluntary curtailment of power are probable. Level II is declared when reserves drop below 5%. Large commercial customers who have signed up to voluntarily curtail power during periods of high demand are asked to do so. If reserves continue to fall below 1.5%, Level III is initiated, where involuntary curtailments of service to customers including "rolling blackouts" are probable.

The ISO's projection of loads and resources for the summer of 2000 expected a shortfall of supply if "Hot Summer" conditions prevailed. Under Hot Summer projections the peak load was estimated to be 48,940 MW with in-area generation contributing 37,700-37,950 MW and net imports from the Pacific Northwest and Southwestern neighboring states adding 6,500-7,100 MW to meet the demand. The ISO also estimated that 2,780 MW of interruptible demand would be available to offset the peak. Assuming interruptible load was not available for curtailment of the peak, under Hot Summer conditions a shortfall of 3,890 MW was expected. And including interruptible load, a shortfall of 1,110 MW was forecast.

Under "Normal Summer" conditions, the ISO projected a net surplus of 100 MW of resources would be available to meet the peak demand. Under Normal Summer conditions, the peak load projection was 46,250 MW with in-area generation contributing 37,700-37,950 MW and net imports from the Pacific Northwest and Southwestern neighboring states adding 7,600-8,400 MW to meet this demand.

3. PJM's market structure and current activity

The market structure in PJM is fundamentally different than its California counterpart. To ensure an adequate supply of electricity over the long-term, California relies exclusively on market forces through the energy and ancillary services markets coupled with intervention by the CA-ISO, if necessary. In contrast, in addition to market forces, the three ISOs in the Northeast, including PJM, rely on another product – installed capacity – and obligations and penalties with respect thereto to ensure an adequate supply of electricity.

Notwithstanding the different philosophies, the PJM region is not immune to increases in wholesale prices and occasional price spikes. In addition, a PJM working group has been commissioned to address certain concerns with market rules as well as the structure of the PJM electric markets. At the center of the debate is the value of a capacity obligation and capacity market in a competitive electric industry. Staff is participating with the group and plans to provide the Commission with a white paper discussing the specific concerns with and possible remedies to the PJM electric market.

The CPUC expressed concern over the potential conflict of interest of members of the CA-ISO and CA-PX Boards. The Boards are composed of persons who are affiliated with entities transacting business in the state's electric markets. In contrast, the members of the Board

of Directors who govern the PJM Interconnection are precluded from have an interest in the PJM electric markets. The PJM Interconnection performs the separate functions of the CA-ISO and the CA-PX. Thus, PJM operates the transmission system as well as the wholesale power markets.

The PJM Interconnection plans the transmission system with input from a committee of interested stakeholders. In California, each of the three major utilities plans its respective transmission system and the CA-ISO coordinates the three efforts. The California approach appears similar to the planning philosophy employed in PJM prior to its transition to an independent system operator.

One measure of market success in the evolving electric industry is the ability to attract additional generating capacity. In both California and PJM significant price increases have been generally attributed to a scarcity of supply. PJM is ahead of California on attracting new generating resources. Currently, PJM is concluding transmission interconnection assessments for nearly 9,000 MW of new generating resources planned to be in service by 2002. While it is unlikely that all 9,000 MW will be constructed, California does not anticipate the construction of any material electric generation by 2002.

The PJM Interconnection operates energy, capacity and ancillary service markets. Until June 2000, the only energy market operated by PJM was the real-time (or spot) energy market. On June 1, 2000, PJM added a day-ahead energy market to enhance the robustness and competitiveness of the PJM energy markets. In 1999, the real-time energy market represented 15% of the overall energy market in PJM. Bilateral transactions represented 30% of the market and the remaining 55% was self-supplied by utilities that owned both generation and served customer load.

Wholesale prices in the PJM energy market for the summer period increased from an average daily price of $29.65/MWh in 1998 to $53.69/MWh in 1999. Over 80% of the increase in the average price are attributable to 15 high demand days in 1999. A high demand day is defined as a day during which the hourly energy price exceeded $130/MWh, which price was the production cost of the most expensive generating unit in PJM prior to the introduction of market-based pricing on April 1, 1999.

On at least one occasion in 1999, the energy prices rose to the maximum allowable price under the $1,000/MWh price cap. The increase in the energy price as a function of system demand followed a similar pattern for three high demand days that were evaluated in detail by the PJM Market Monitoring Unit ("MMU"). The energy price increased to approximately $50/MWh as the PJM system demand increased to over 40,000 MW. For the next 3,500 MW to 5,000 MW incremental increase in the system demand, the energy price rose from $50/MWh to the $130/MWh benchmark. For the last 400 MW to 700 MW increase in system demand, the energy price rose to the $850/MWh - $950/MWh range.

The PJM MMU has concluded that certain generator owners can "profitably raise the market price above the competitive level". The ability exists when supply is scarce and the generator owners are net sellers into the PJM system. The PJM MMU believes that market

power was exercised, but it is unable to quantify the impact since wholesale prices above the $130/MWh threshold were necessary to attract energy from generating resources outside the PJM region. Thus, part of the price increase above $130/MWh was deemed a legitimate "scarcity rent" and part was the result of market power.

Due to the relatively mild summer this year, the PJM energy market was not tested to the degree it was last summer. Thus, it is difficult to compare the performance of the PJM energy market to last summer. Through August 28, 2000, the PJM average daily spot price exceeded the $130/MWh threshold on only one occasion.

The PJM MMU recommends changing certain market rules and market designs to improve the functionality of the PJM wholesale electric markets. PJM committees are currently reviewing the recommendation. The PJM MMU is referring not only to the energy market in PJM, but also the capacity markets.

Long-term adequacy for the PJM region is currently the responsibility of the Reliability Assurance Committee ("RAC") pursuant to the Reliability Assurance Agreement ("RAA") among the load serving entities ("LSEs") in the PJM control area. At a recent RAC meeting, the PJM Board issued an ultimatum to the LSEs to fix the flaws in the capacity markets or the Board will act *sua sponte* to do so. The PJM staff noted that it does not wish to enter next summer without modifying some of the current market rules and it is prepared to make changes without stakeholder participation, if necessary. The market flaws are being addressed by the aforementioned PJM working group and will be discussed in staff's white paper.

The adequate level of capacity to ensure a reliable electric system is determined two years in advance in accordance with established reliability criteria. The purpose for looking forward two years is to provide an appropriate signal that will encourage new generating resources when necessary. The adequate level of capacity becomes an annual capacity obligation under the RAA. The LSEs in PJM are responsible for their share of the obligation, which share is determined by each LSE's customer load. If an LSE does not meet its obligation, the deficient LSE is assessed a monetary penalty. The penalty is an additional incentive to ensure a sufficient level of generating capacity in the PJM region.

PJM has created several capacity credit markets to assist in the acquisition and sale of capacity. The PJM capacity markets represent only approximately 4% of the capacity market in PJM. Bilateral transactions represent nearly 40%. The remaining portion of the market is covered by LSEs that also own generation.

The price in the PJM capacity markets increased significantly during the June – August period this summer versus the same period in 1999. In 1999, the price ranged from $0/MW-day to $35/MW-day over the period. This year, the price ranged from mostly $170/MW-day to $350/MW-day. The capacity market price is effectively capped at the capacity deficiency penalty, which ranges between $177/MW-day and $354/MW-day. Thus it appears that the market price repeatedly capped out at the maximum price for most of the summer. Some marketers have expressed concern over the sudden increase in the capacity price. In May 2000, the average capacity price was merely $35/MW-day. The PJM MMU has concluded

preliminarily that market power was not the culprit behind the unexpected price increase. PJM is the process of assessing and establishing market-based bidding for its ancillary service markets.

In sum, the PJM market structure is fundamentally different than its California counterpart. The concept behind the capacity obligation in PJM is to encourage the construction of new generating resources and penalize those that do not fulfill their obligation. Another measure of market success is the willingness to participate in the marketplace. PJM appears to be ahead on this front as well. According to PJM data, the PJM west hub is the most liquid regional transaction point in this country. In May, June, and July, the hub transacted four to slightly over five times more volume in energy than any other regional market hub. Overall, the PJM wholesale markets have performed well. There are several concerns with some rules and market designs, but sufficient encouragement has been provided to address the concerns.

V: ENERGY CONSERVATION, RENEWABLES AND ENVIRONMENTAL ISSUES

A. Statutory Requirements

Section 7-201(b)(2) requires the Commission to evaluate the cost-effectiveness of the investments by electric companies in energy conservation measures and practices to reduce electrical demand and in renewable energy sources to help meet electric demand. This includes:

(a) An electric company's promotion and conduct of a building, audit and weatherization program;
(b) utilization of renewable resources;
(c) promotion and utilization of electricity from cogeneration and wastes; and,
(d) widespread promotion of energy conservation programs.

Section 7-211 requires gas and electric utilities in Maryland to develop and implement energy efficiency and conservation programs, subject to review and approval of the Commission. This section further states that the Commission requires a utility to establish any such program or service that the Commission finds to be both cost-effective and appropriate. The Commission is required to adopt ratemaking policies for programs that encourage energy efficiency and conservation. Further, the Commission is empowered to consider reasonable financial incentives to participating utilities.

B. Report to the General Assembly

Section 7-211 (c) of the Public Utility Companies Articles requires the Commission, in cooperation with the Maryland Energy Administration, to prepare a report by February 1, 2001. Such a report will discuss the current status of programs and services to promote conservation of energy and a recommendation for an appropriate level of funding for these programs and services. This report will also consider, among other things, the impact on jobs, environmental impacts, rate impacts and the cost-effectiveness in determining whether a program or service encourages and promotes conservation.

By letter dated May 12, 2000, the Commission invited Parties of Record and Interested Persons to address three questions related to fulfillment of the provisions of Section 7-211 (c) These question are: (1) What type of energy conservation and efficiency programs should be adopted? As directed by the Commission, the parties submitted proposed programs on August 28, 2000. This proceeding is ongoing. The information gathered in this proceeding would form a part of the report to the General Assembly.

C. Current Utility Activities [17]

This section provides a summary of utility efforts during 1999 to implement the provisions of Section 201 of the Public Utility Companies Articles. The information presented below are the responses of each utility to a data request asking what efforts were made during 1999 to analyze energy efficiency and conservation programs, including the weatherization of

[17] The following utilities did not respond: A&N Electric Cooperative; Conectiv; Easton; and Williamsport.

buildings, renewable energy, cogeneration, and widespread promotion of energy conservation programs.

Baltimore Gas and Electric

BGE continues to operate its Low-Income Conservation Home Improvement Program (CHIP) which weatherizes gas and electric homes. In addition, on February 7, 2000 BGE filed with the Commission a request to expand its gas portion of CHIP. This expansion provides up to $500,000 annually for the purpose of replacing inoperable or inefficient gas furnaces and boilers. This program will continue through 2002. This modification to CHIP was subsequently approved by the Commission. In addition, BGE continues to offer free commercial and residential energy audits. These audits analyze the building envelope, HVAC, water heating, and lighting and provide feedback on what changes can be made to reduce customer's energy costs. BGE's electric service tariff, Rider 18, provides net metering to eligible customers for installing an electric generating facility. And BGE's electric service tariff, Schedule X-cogeneration and small power producers, provides for energy and capacity payments to qualifying facilities at avoided costs.

Berlin

In previous IRPs, Berlin has included energy savings information on various demand side management activities. A compact fluorescent light bulb discount program was completed in April 1994 with a total of 98 light bulbs distributed. Energy savings from these light bulbs have been discounted each year since the program was completed. For the year 2000 no savings are being shown from the program since its expected lifetime was five years.

Choptank Electric Cooperative

Choptank has not performed any analysis or contracted for a study of the cost effectiveness of investments in energy conservation measures during the time from January 1, 1999 to now. However, Choptank has participated in the following energy conservation type programs during the past 2 years:

(a) Choptank (in conjunction with Old Dominion Electric Cooperative) has an agreement with All Phase to conduct building audit and weatherization programs for Commercial and Industrial accounts. Choptank is currently working with the largest customer on Choptank's system on a lighting survey to see where the plant can increase fixture efficiencies. The Cooperative undertook a similar initiative at its headquarters' office building in the summer.

(b) Choptank continues to offer residential audits. Choptank offers weatherization diagnostics for residential members. Choptank also has available an unsecured loan program for energy efficient projects that our members would like to undertake.

(c) Choptank would encourage renewable energy resources to the extent members would like to participate in such programs. For example, Choptank has a tariff rider for Residential Service Solar Electric Generation customers that may want to install solar collectors or panels.

(d) Choptank (in conjunction with its power supplier, Old Dominion Electric Cooperative) would work with any member that desires to produce electricity from cogeneration and wastes.

(e) Choptank has frequently promoted some type of energy conservation program. Choptank has brochures that highlight energy conservation tips. We also have similar conservation tips available on our web site.

Hagerstown

In 2000, the City of Hagerstown Light Department will have over 967 participants in its demand-side management (DSM) programs contributing an estimated .014 MW towards meeting the 2000 summer peak. Although no new program offerings are planned in 2000, existing measures are expected to continue to have a .03 MW impact through the year 2014. By the year 2014, it is estimated that DSM will continue to contribute .014 MW towards reducing the summer peak, and the 15-year cumulative energy savings will be over 1,954 GWh. The growth in DSM over the next 15 years is estimated to offset almost 0.2% of the growth in native peak demand and 0.2% of the growth in energy sales. The City will continue to evaluate DSM's role in its resource mix. However, Hagerstown will continue to seek new opportunities for cost-effective peak-clipping and load-shifting programs.

Pepco

Pepco has examined the cost-effectiveness of two conservation programs since January 1, 1999. These programs are the Maryland High Efficiency Air Conditioner and Heat Pump Program and Pepco funding in support of the installation of certain electricity related conservation measures through the Maryland Weatherization Assistance Program. Pepco determined that program costs exceeded benefits for the High Efficiency Air Conditioner and Heat Pump Program under both the All-Ratepayers Test and the Rate Impact Measure Test. Based on these results, Pepco and the Conservation Collaborative recommended to the Commission that the Program be discontinued; the Commission subsequently approved the discontinuation of the Program. Pepco determined that funding in support of the Maryland Weatherization Assistance Program passed the All Ratepayers Test, but failed the Rate Impact Measure Test. Based on these results, Pepco and the Conservation Collaborative recommended Pepco funding of this program and the Commission subsequently approved that funding. Since January 1, 1999, Pepco has not conducted any other studies concerning the cost-effectiveness of conservation, renewable energy sources, or the production of electricity from cogeneration and wastes.

Potomac Edison/Allegheny Power

Allegheny Power has discontinued its traditional demand-side management programs, with the exception of a few small programs to assist low-income customers. Allegheny Power continues to evaluate the potential of emerging technologies for reducing costs, increasing efficiency, and improving overall system load factor through the Electric Power Research Institute (EPRI) and its own internal research and development programs. Allegheny Power believes that as restructuring of the electric utility industry continues, market forces will drive

the development and implementation of cost-effective energy efficient technologies along with peak load management initiatives.

Allegheny Power has introduced a new demand-side peak management program in all jurisdictions. The Generation Buy-Back Program enables Allegheny Power to buy-back electric generation capacity from its customers that have on-site generation or operational flexibility during high-cost periods. The Generation Buy-Back Program seeks to register customers who wish to be considered for notification and given an opportunity to enter into generation buy-back transactions when market conditions are economically attractive for both the customer and Allegheny Power. The Company uses the capacity to offset purchases from the wholesale market or to provide capacity to the wholesale market. Allegheny Power has 34 MW enrolled in the Generation Buy-Back Program with an additional 30 MW close to agreement. Allegheny Power anticipates enrollment to reach 100 MW in 2001.

Somerset Rural Electric Cooperative

The cooperative continues to operate its load management plan. Load control switches are installed on water heaters and Electric Thermal Heat (ETH). The load management effort lowers the peak demand by shifting the load to an off-peak time. Savings are in demand reduction but not in energy sales. The cooperative offers energy audits to help members with conserving energy. Weatherization advice and new energy efficient appliance information is dispersed to members through the cooperative's monthly magazine, *Penn Lines.* No cost-effective analysis has been conducted.

Southern Maryland Electric Cooperative

In 1997, SMECO contracted with the Vermont Energy Investment Corporation (VEIC) to conduct an analysis of the PowerSaver Home program. VEIC's performed on-site inspections, blower door tests, and billing analyses on PowerSaver Homes and baseline homes. The new homes built under SMECO's DSM program were found to be very efficient, with energy savings of over 40 percent and demand savings over 40 percent.

When SMECO transformed the rebate program into the market-driven Energy Star Home program, the construction specifications remained basically the same. To promote the Energy Star Home program, SMECO developed a brochure which highlights the energy savings new homeowners can expect. The savings analysis compares the cost of a standard home to the cost of an Energy Star Home. The figures show that even though the Energy Star Home costs more and the customer's mortgage is increased, the lower monthly energy bill provides a greater savings..

Town of Thurmont

No analyses have been conducted or contracted for which evaluate the cost-effectiveness of energy conservation measures sponsored by the Thurmont Municipal Light Company since January 1, 1999. No demand-side resources are included in the Town of Thurmont's 2000 Long-Range Plan. Due to a very low customer response rate to a previous DSM program and the

current state of DSM throughout the State, the Town of Thurmont is cautious in its consideration of any new DSM initiatives.

D. Impact of deregulation on conservation programs

During the past three years there has been a major contraction of utility-sponsored DSM programs in Maryland. This contraction is the result of two factors that are transforming the electric utility industry across the country. First, the costs of new supply options have fallen substantially over the past decade. This is due to lower fuel costs, improved efficiencies in new supply options, and the expansion of competition in wholesale markets. Consequently, DSM programs, which may have been cost-effective at the time they were implemented, are no longer cost-effective. These programs have either been restructured or discontinued.

The second factor concerns the introduction of retail competition in Maryland. For the past few years utilities and customers in this state have expressed concern about the impact of DSM programs on their customers' rates. Much of this concern was focused on the use of rebates and other direct incentives to promote participation in DSM programs. Specifically, utilities and other interested parties expressed concerns about the total costs of rebate programs and their effect on rates, particularly in terms of fairness. A concern expressed by some commercial and industrial customers was that the costs of programs are distributed among all customers in a given class while the benefits accrue largely to program participants. Additionally, utilities have expressed concern that the costs of such programs could effect their ability to retain customers in a more competitive environment. These concerns are not limited to Maryland *per se*, but have been expressed nationwide.

E. Energy Management Providers in Maryland

This section addresses the types of companies providing energy management services in the private sector, the technological developments that are stimulating the growth of these energy management service companies, and the types of electric customers that typically use these services. The information found in this section was gathered from a number of sources including government publications, trade organizations and industry resources.

Many types of businesses provide energy management services. They include energy service companies (ESCOs), energy suppliers, manufacturers of energy efficiency equipment, facility management companies, independent contractors, and consultants. An Energy Service Company (ESCO) is a company engaged in developing, installing and financing comprehensive, performance-based energy efficiency projects that improve the energy efficiency and lower the maintenance costs for facilities.

Energy management companies primarily serve large commercial and industrial customers, including retail chains, large banks, large restaurant and fast food chains and hotel operators. In addition, industrial and institutional customers have reported using energy management services to analyze and consolidate electric bills, reduce energy price risk, procure power and make infrastructure improvements to reduce energy consumption.

At this time there are very few energy management companies serving the residential customer provide comprehensive services. Many firms provide insulation, high-efficiency windows, and HVAC equipment in Maryland. There are few in Maryland that provide these services comprehensively or provide advance-sealing treatments by the use of a blower door test. Unlike an ESCO that addresses electricity end-uses in a facility, residential services tend to be fragmented.

Restructuring of the energy industry may intensify competition in energy management markets. Some market research indicates that marketers anticipate that the introduction of customer choice could result in smaller margins on bulk power services. Energy suppliers will have limited options for offering lower prices to customers, including reducing administrative costs and helping customers to lower energy usage. One option to improve margins is to offer energy services in addition to bulk power[18][19]. This has led to an increase in the types of companies, such as competitive energy suppliers and facility managers, which provide energy service, as part of a "total energy service" package. Deregulation has also enabled large energy management service companies to offer service to large commercial multi-site establishments across utility and state boundaries.

Staff was not able to identify any studies that have been performed about the current level of energy services available to customers in Maryland. There is anecdotal evidence that suggests energy service providers are providing services to larger commercial and industrial customers. Additionally there is no evidence to suggest that the experience of Maryland is different from other jurisdictions or that significant barriers now exist that would prevent further development of energy service industries in Maryland.

At this point, it appears that a competitive market exists to provide energy services to large commercial, industrial and institutional customers in the State. It is difficult to determine, on the basis of this review, the extent to which these firms capture the available energy efficiency measures. Staff was unable to determine if these programs are capturing only the most profitable efficiency measures and not addressing other smaller cost-effective efficiency measures. It appears that the private market focuses on larger commercial and industrial customers and that markets are not addressing energy efficiency and conservation opportunities for small businesses and residential customers.

F. Renewable Energy

1. Renewable Portfolio Standard Report

Section 7-516 (c) of the Public Utility Companies Articles provides that the Commission in consultation with the Maryland Energy Administration shall report to the governor and the General Assembly on the feasibility of requiring a renewable portfolio standard. This report was submitted to the General Assembly in June 2000.

---

[18] *Ibid.*

[19] Marketing-Savvy Energy Companies Use Smart Solutions, Right Price to Turn Business Prospects Into Customers, October 22, 1999, Atlanta, Oct. 21, PRNewswire via NewsEdge Corporation.

2. Section 7-516(b) of the Public Utility Companies Articles

Section 7-516(b) of the Public Utility Companies Articles requires that investor-owned electric companies shall continue to provide as least the same percentage of electricity from available renewable energy resources, at a reasonably comparable cost, as the electric company provided in 1998. The table below provides a summary of these percentages for each electric company in 1998 and will provide the benchmark for determining if a company has complied with the provisions of this statute in the delivery of regulated (standard offer service) to their customers in future years.

Table 5: Electricity Generation From Renewable Energy Resources, 1998

Utility	Total Generation (MWh)	Maryland Generation (MWh)	Total Renewables (MWh)	Maryland Allocation	Maryland Renewables (MWh)	Percent Maryland Renewables
BGE	30,840,610	30,840,610	1,038,772	100.00%	1,038,772	3.368%
DPL	14,295,200	4,164,440	448	29.13%	131	0.003%
PE	14,422,530	9,287,600	38,659	64.40%	24,895	0.268%
Pepco	28,138,860	17,132,840	280,500	60.89%	170,787	0.997%
TOTAL	**87,697,200**	**61,425,490**	**1,358,379**		**1,234,585**	**2.009%**

G. Emission Disclosures

Section 7-505(b)(4) of the Public Utility Companies Articles states that the Commission shall, by regulation or order, require each electric company and electricity supplier to provide adequate and accurate information to each customer on the available electric services of the electric company or electricity supplier. Section 7-505(b)(4) further requires that the information provided to customers shall include disclosure, every 6 months, of a uniform common set of information about the fuel mix of the electricity purchased by customers and the emissions on a pound per megawatt-hour basis of pollutants identified by the Commission, or disclosure of a regional fuel mix average. On June 15, 2000, the Public Service Commission issued Order No. 76241 ("Order"), which among other things, adopted rules for the disclosure of emissions and fuel mix data by electric companies and electricity supplies to Maryland retail customers.

The Commission in its Order requested that a uniform regional approach to fuel mix and emissions disclosure is desirable. In the interim, the Commission found that the Environmental Information Disclosure Rules proposed by Staff, with appropriate modifications, meet the important objectives of ensuring that adequate and accurate fuel mix and emissions disclosures are made to electricity consumers, and that disclosure may encourage the development and/or procurement of more renewable energy generation for distribution to Maryland's electricity consumers. The Commission directed the Emissions Disclosure Working Group (EDWG) to coordinate with other states in the region to promote a single regional approach to fuel mix and emissions disclosures. The EDWG is working to identify areas for regional cooperation that would provide both adequate and accurate information to consumers about fuel mix and emissions, while minimizing the cost to suppliers in Maryland and the region. Areas of potential cooperation include uniform label formats and the development of a regional system to track emissions and fuel mix data for suppliers in the region.

Pursuant to Section 7-516 (d) of the Public Utility Companies Articles requires electric companies to conduct a study that tracks shifts in generation and emissions as a result of restructuring of the electric industry one year after its implementation. If after review of the study the Maryland Department of the Environment determines that the emissions levels impose a higher burden in Maryland, MDE in consultation with the Commission, shall study the appropriateness, constitutionality, and feasibility of establishing and air quality charge or other mechanism to protect Maryland's environment in connection with the implementation of customer choice in Maryland. The study is due to be submitted to MDE before July 1, 2001.

APPENDIX
Tables A-1 to A-10

TABLE A-1: UTILITIES PROVIDING RETAIL ELECTRIC SERVICE IN MARYLAND	
Utility	**Service Territory**
A&N Electric Cooperative (A&N)	Smith Island in Somerset County.
Baltimore Gas & Electric Company (BGE)	Anne Arundel County, Baltimore City, Baltimore County and portions of the following counties: Calvert, Carroll, Howard, Harford, Montgomery, and Prince George's.
Town of Berlin (Berlin)	Town of Berlin.
Choptank Electric Cooperative (Choptank)	Portions of the Eastern Shore.
Delmarva Power & Light Company (DPL)	Major portions of ten counties primarily on the Eastern Shore.
Easton Utilities Commission (Easton)	City of Easton.
Hagerstown Municipal Electric Light Plant (Hagerstown)	City of Hagerstown.
Potomac Edison Company (PE)	Parts of western Maryland.
Potomac Electric Power Company (PEPCO)	Major portions of Montgomery and Prince George's Counties.
Somerset Rural Electric Cooperative (Somerset)	Northwestern corner of Garrett County.
Southern Maryland Electric Cooperative (SMECO)	Charles and St. Mary's Counties; portions of Calvert and Prince George's Counties.
Thurmont Municipal Light Company (Thurmont)	Town of Thurmont
Town of Williamsport (Williamsport)	Town of Williamsport

Table A-2:
Number of Customers by Customer Class (as of December 31,1999)

	System-Wide						Maryland					
Utility	**Resi-dential**	**Com-mercial**	**Indus-trial**	**Other**	**Sales for Resale**	**Total**	**Resi-dential**	**Com-mercial**	**Indus-trial**	**Other**	**Sales for Resale**	**Total**
A&N	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
BGE	1,021,436	103,590	8,776	0	0	1,133,802	1,021,436	103,590	8,776	0	0	1,133,802
Berlin	1,426	238	58	12	0	1,734	1,426	238	58	12	0	1,734
Choptank	37,323	2,569	15	256	0	40,163	37,323	2,569	15	256	0	40,163
DPL	406,487	52,049	634	661	12	459,843	153,843	22,128	273	306	2	176,552
Easton	6,881	1,792	0	125	0	8,798	6,881	1,792	0	125	0	8,798
Hagerstown	14,735	2,153	136	4	0	17,028	14,735	2,153	136	4	0	17,028
PE	346,821	45,968	5,235	590	10	398,624	185,575	22,616	2,495	328	3	211,017
Pepco	624,802	71,292	0	149	2	696,245	430,980	45,222	0	118	1	476,321
Somerset	11,277	906	7	0	0	12,190	708	35	0	0	0	743
SMECO	107,888	9,867	4	133	0	117,892	107,888	9,867	4	133	0	117,892
Thurmont	2,264	317	9	45	0	2,635	2,264	317	9	45	0	2,635
Williamsport	746	61	33	24	0	864	746	61	33	24	0	864
Total	**2,582,086**	**290,802**	**14,907**	**1,999**	**24**	**2,889,818**	**1,963,805**	**210,588**	**11,799**	**1,351**	**6**	**2,187,549**

Table A-3:
Sales by Customer Class (GWh)
(as of December 31, 1999)

	System-Wide						Maryland					
Utility	**Resi-dential**	**Com-mercial**	**Indus-trial**	**Other**	**Sales for Resale**	**Total**	**Resi-dential**	**Com-mercial**	**Indus-trial**	**Other**	**Sales for Resale**	**Total**
A&N	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
BGE	11,349	3,141	14,774	0	0	29,264	11,349	3,141	14,774	0	0	29,264
Berlin	15	3	27	0	1	46	15	3	27	0	1	46
Choptank	471	30	175	0.4	0	676	471	30	175	0.4	0	676
DPL	4,472	4,311	3,614	71	1,251	13,719	1,808	1,446	527	19	190	3,990
Easton	83	146	0	10	0	239	83	146	0	10	0	239
Hagerstown	128	60	128	7	0	323	128	60	128	7	0	323
PE	4,631	2,658	5,835	22	662	13,808	2,525	1,537	4,169	14	430	8,675
Pepco	7,013	16,587	0	610	2,760	26,970	5,370	8,192	0	229	2,756	16,547
Somerset	102	35	9	0	0	146	5	1	0	0	6	12
SMECO	1,555	898	172	5	0	2,630	1,555	898	172	5	0	2,630
Thurmont	32	15	23	1	0	71	32	15	23	1	0	71
Williamsport	9	1	6	0	1	17	9	1	6	0	1	17
Total	**29,860**	**27,885**	**24,763**	**726.4**	**4,675**	**87,909**	**23,350**	**15,470**	**20,001**	**285.4**	**3,384**	**62,490**

Table A-4: Typical Utility Bills in Maryland, Winter 2000						
	Typical Bill			Revenue: cents/kWh		
	Residential	**Commercial**	**Industrial**	**Residential**	**Commercial**	**Industrial**
A&N	n/a	n/a	n/a	n/a	n/a	n/a
BGE	$63.99	$858.00	$11,824.00	8.60	6.93	4.70
Berlin	$67.40	$1,219.40	$12,665.35	8.86	9.52	6.22
Choptank	$73.33	$1,212.62	$15,236.21	9.40	7.39	6.97
DPL	$71.55	$1,377.81	$14,057.67	9.54	11.02	7.03
Easton	$63.97	$1,051.05	0	6.50	6.50	n/a
Hagerstown	$37.19	$671.55	$7,143.19	n/a	n/a	n/a
PE	$49.39	$805.50	$9,581.00	6.58	6.44	4.79
PEPCO	$62.70	$1,017.86	$12,299.18	8.36	8.14	6.15
Somerset	$73.15	$955.90	$12,730.06	9.80	7.60	6.40
SMECO	$70.01	$1,062.41	$13,073.83	9.30	8.50	6.50
Thurmont	$41.29	$624.75	$7,811.00	5.40	4.86	3.81
Williamsport	$39.50	$664.44	$9,254.40	5.26	5.32	4.62

Table A-5:
Energy Input by Utility (GWh)
(as of December 31, 1999)

Utility	Fossil[20]	Hydro	Nuclear	Cogeneration	Other	Net Interchange	Purchases	Total
A&N	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
BGE	19,374 53.9%	541 1.5%	13,309 37.1%	255 .7%	571 1.6%	563 1.6%	1,302 3.6%	35,915 100%
Berlin	2.56 5.4%	n/a	n/a	n/a	n/a	n/a	45.04 94.6%	47.60 100%
Choptank	n/a	n/a	n/a	.1	n/a	n/a	728.9 99.9%	729 100%
DPL	7,373	0	2,521	0	0	2,930	1,732	14,556 100%
Easton	41.6 16.6%	n/a	n/a	n/a	n/a	209.0 83.4%	n/a	250.7 100%
Hagerstown	n/a	n/a	n/a	n/a	n/a	n/a	336.5	336.5 100%
PE	11,483.5	26.7	0	108.5	-483.3	3,247.3	4,393.9	18,776.6
PEPCO	22,807	0	0	311	0	4,171	3,396	30,685 100%
Somerset	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
SMECO	n/a	n/a	n/a	n/a	n/a	n/a	2,756 100%	2,756 100%
Thurmont	n/a	n/a	n/a	n/a	n/a	n/a	74.61 100%	74.61 100%
Williamsport	n/a	n/a	n/a	n/a	n/a	n/a	18.8 100%	18.8 100%

[20] Includes steam and combustion turbines.

Table A-6: **Peak Demand Forecast , 2000-2014** (Net of DSM Programs)													
Year	**A&N**	**Berlin**	**BGE**	**DPL**	**Chop-tank**	**Easton**	**Hagers-town**	**PE**	**PEPCO**	**Som-erset**	**SMECO[21]**	**Thur-mont**	**Williams-port**
2000	n/a	10.18	6,500	3,111	177.9	52.3	75.09	2,669	5,072	40.6	*	17.76	4.50
2001	n/a	10.33	6,610	3,152	183.2	53.8	77.35	2,727	5,132	41.3	*	18.03	4.53
2002	n/a	10.48	6,740	3,204	188.8	55.3	79.67	2,779	5,207	42.4	*	18.30	4.55
2003	n/a	10.64	6,860	3,254	194.9	56.6	82.06	2,824	5,294	43.5	*	18.57	4.57
2004	n/a	10.80	6,960	3.304	201.0	57.9	84.52	2,876	5,409	44.7	*	18.85	4.60
2005	n/a	10.96	7,080	3,362	206.7	59.1	87.06	2,911	5,548	45.9	*	19.13	4.62
2006	n/a	11.13	7,150	3,422	212.7	60.4	89.67	2,944	5,702	46.9	*	19.42	4.64
2007	n/a	11.29	7,210	3,489	218.7	61.6	92.36	2,976	5,845	48.5	*	19.71	4.67
2008	n/a	11.46	7,280	3,550	224.8	62.9	95.13	3,006	5,993	49.6	*	20.01	4.69
2009	n/a	11.63	7,340	3,615	230.9	64.2	97.99	3,036	6,143	51.3	*	20.31	4.71
2010	n/a	11.81	7,380	3,661	237.1	65.4	100.9	3,066	6,296	52.4	*	20.61	4.74
2011	n/a	11.99	n/a	n/a	243.3	66.7	103.9	3,096	6,441	53.7	*	20.92	4.76
2012	n/a	12.17	n/a	n/a	249.5	68.0	107.8	3,130	6,587	54.8	*	21.23	4.78
2013	n/a	12.35	n/a	n/a	255.7	69.2	110.2	3,163	6,740	55.7	*	21.55	4.81
2014	n/a	12.53	n/a	n/a	261.9	70.5	113.6	3,199	6,901	56.5	*	21.88	4.86

[21] SMECO alleges that this information is confidential

Table A-7: **Energy Sales Forecast, 2000-2014** (GWh)													
Year	**A&N**	**Berlin**	**BGE**	**DPL**	**Chop-tank**	**Easton**	**Hagers-town**	**PE**	**PEPCO**	**Somerset**	**SMECO[22]**	**Thur-mont**	**Williams-port**
2000	n/a	45.69	32,064	12,892	700.1	251.1	333.0	13,997	24,561	152	*	71.7	19.4
2001	n/a	46.37	32,715	13,209	724.4	258.2	343.0	14,315	25,022	154	*	72.7	19.6
2002	n/a	47.07	33,348	13,501	750.0	265.4	353.3	14,591	25,433	156	*	73.8	19.7
2003	n/a	47.78	33,942	13,794	777.8	271.7	363.9	15,111	25,893	158	*	74.9	19.8
2004	n/a	48.49	34,541	14,085	806.1	277.9	374.8	15,545	26,504	160	*	76.1	19.9
2005	n/a	49.22	34,983	14,379	832.2	283.7	386.1	15,682	27,203	162	*	77.2	20.0
2006	n/a	49.96	35,484	14,660	859.3	289.9	397.7	15,869	27,975	164	*	78.4	20.1
2007	n/a	50.71	35,958	14,940	886.9	295.7	409.6	16,031	28,693	166	*	79.5	20.2
2008	n/a	51.47	36,514	15,215	914.8	301.9	421.9	16,228	29,441	168	*	80.7	20.3
2009	n/a	52.24	36,837	15,490	942.9	308.1	434.5	16,257	30,186	170	*	81.9	20.4
2010	n/a	53.02	37,215	15,765	971.2	313.9	447.6	16,355	30,944	173	*	83.2	20.5
2011	n/a	53.82	n/a	n/a	999.6	320.1	461.0	16,530	31,675	174	*	84.4	20.6
2012	n/a	54.63	n/a	n/a	1,028.0	326.4	474.9	16,797	32,416	176	*	85.7	20.7
2013	n/a	55.45	n/a	n/a	1,056.3	332.1	489.1	16,955	33,189	177	*	87.0	20.8
2014	n/a	56.28	n/a	n/a	1,084.5	338.4	503.8	17,169	33,993	179	*	88.3	20.9

[22] SMECO alleges that this information is confidential

Table A-8: Proposed Sites for New Electric Generating Stations in Maryland (as of December 31, 1999)				
Company	**Site**	**Ownership (%)**	**Potential Use**	**In-Service Date**
BGE	Perryman	100%	Unspecified	n/a
BGE	Riverside	100%	Unspecified	n/a
BGE	Brandon Shores	100%	Unspecified	n/a
BERLIN	To be determined	100%	Co-generation; waste heat recovery; peak shaving	Unspecified
BERLIN	To be determined	100%	Peak shaving; economic dispatch	Unspecified
DP&L	Vienna Power Plant, Dorchester County, MD	100%	Combustion Turbine	Unknown
DP&L	Handley site, Dorchester County, MD	100%	Combustion Turbine	Unknown
PEPCO	Douglas Point, Charles County, Maryland	100%	*See Note*	*See Note*

Note: PEPCO has entered into a contract to sell the property.

Table A-9:
Transmission Additions 2000 to 2014
(in Excess of 69 kV)

Utility	No. of Circuits	From Location County, Terminal	To Location County, Terminal	Construction Start - End	Purpose	Voltage
BGE	1	Baltimore City, Lakespring	Baltimore City, Texas	1/1/00 – 6/1/01	D1	230
BGE	1	Baltimore City, Greene St.	Baltimore City, Concord St.	8/1/00 – 6/1/02	D1	115
BGE	1	Baltimore City, Concord St.	Baltimore City, Monument St.	8/1/00 – 6/1/02	D1	115
BGE	1	Harford County, Five Forks	Harford County, Rock Ridge	6/1/01 – 12/1/01	D1	115
BGE	1	Baltimore County, Windy Edge	Baltimore City, Erdman	2/1/02 – 6/1/02	D1	115
DP&L	1	Somerset, Loretto	Somerset, Kings Creek	11/1/00 – 5/1/01	D3	138
DP&L	1	Somerset, Kings Creek	Somerset, Costen	11/1/00 – 5/1/01	D3	138
DP&L	1	Somerset, Costen	Somerset, Pocomoke	11/1/00 – 5/1/01	D3	138
DP&L	1	Somerset, Pocomoke	Accomack, VA, Oak Hall	11/1/00 – 5/1/01	D3	138
DP&L	1	Wicomico, Vienna	Sussex, DE, Neslon	09/3/03 – 5/1/07	D4	138
SMECO	2	Holland Cliff Switching Station	Lusby, Calvert Cliffs Tap	2004 - 2006	S-1	230
SMECO	2	Lusby, Calvert Cliff	Calvert Cliffs, Calvert Cliff	2006 - 2007	S-2	230
SMECO	2	Lusby, Calvert Cliff	Lexington Park, Hewitt Rd	2007 - 2008	S-3	230

Purpose Key

D1. Transmission contingency overloads between 0 and 10%
D2. Distribution overloads between 0 and 10%
D3. Associated with IPP generation addition
D4. Rebuild of an existing line
D5. New line a short distance from an existing transmission line to a distribution substation

S1. Establish 230 kV supply to Culvert Cliffs Switching Station
S2. Establish 230 kV supply to Culvert Cliffs Switching Station
S3. Complete 230 kV loop through the south-eastern half of SSMC's service territory

Table A-9: (continued)
Potomac Edison Company
Proposed Transmission Lines (2000-2014)

Proposed Transmission Line	Connecting Point	No. of Circuits	Operating Voltage (kV)	Design Voltage (kV)	Completion Year*	Cost ($000)	Purpose
New Market Loop	Eaglehead - Mt. Airy	2	230	230	2000	8,100	Area Supply
Carroll - Lehigh Portland Cement	Carroll - Lehigh Portland Cement	1	138	138	2001	1,056	Industrial Expansion
Millville - Doubs (Rebuild)	Millville - Doubs	1	138	138	2001	971	Transmission Supply
Old Farm Loop	Monocacy - Ringgold	2	230	230	2002	2,682	Area Supply
Boonsboro - Frostown (Rebuild)	Boonsboro - Frostown	1	230	230	2003	8,682 Combined total; both lines belong to same project.	Area Supply
Marlowe - Boonsboro (Rebuild)	Marlowe - Boonsboro	1	138	138	2003		Area Supply
Paramount No. 1 Loop	Halfway - Reid	2	138	138	2004	3,570	Area Supply
Ridgeville Loop	Mt. Airy - Damascus	2	230	230	2005	4,514	Area Supply
Urbana Loop	Lime Kiln - Montgomery	2	230	230	2005	4,050	Area Supply
South Frederick No. 1 Loop	Monocacy - Lime Kiln	2	230	230	2006	3,629	Area Supply
Clear Spring	Nipetown - Reid	1	138	138	2007	7,858	Area Supply
Jefferson No. 1 Loop	Doubs - Monocacy	2	230	230	2007	3,584	Area Supply

Table A-9: (continued) **Potomac Edison Company** **Proposed Transmission Lines (2000-2014)**							
Proposed Transmission Line	**Connecting Point**	**No. of Circuits**	**Operating Voltage** (kV)	**Design Voltage** (kV)	**Completion Year***	**Cost ($000)**	**Purpose**
Lappans No. 1 Loop	General Office No. 1 - Boonsboro	2	138	138	2007	5,802	Area Supply
Black Oak - Ridgeley - Cumberland	Black Oak - Ridgeley - Cumberland	1	138	138	2008	1,509	Transmission Supply
Catoctin - Emmitsburg	Catoctin - Emmitsburg	1	138	138	2008	9,310	Area Supply
Bucklodge - Montgomery	Dickerson - Quince Orchard	1	230	230	2010	Cost not available. Project is timed beyond budget range.	Transmission Supply
Cresaptown Loop	Carlos Junction - Ridgeley	2	138	138	2010		Area Supply
Legore No. 1 Loop	Catoctin - Carroll	2	138	138	2010		Area Supply
Thayerville Loop	Albright - Mt. Zion	2	138	138	2010		Area Supply
Hyattstown Loop	Lime Kiln - Montgomery	2	230	230	2011		Area Supply
Adamstown Loop	Doubs - Lime Kiln	2	230	230	2012		Area Supply
Green Valley Loop	Damascus - Mt. Airy	2	230	230	2012		Area Supply
General Office No. 1 Loop	Marlowe - Boonsboro	2	138	138	2013		Area Supply

Table A-10
Renewable Energy Projects Providing Capacity and Energy to Maryland Customers

Utility	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)*	1999 Net Generation (MWh)	In-Service Date
BGE	Alternative Energy Associates (AEA) Brighton Dam	Laurel, MD	Yes	Hydro, runoff from water treatment plant	0.36	436	1/86
BGE	AMSTAR Corp/Domino Sugar Refinery	Baltimore, MD	Yes	No.6 Oil, Natural Gas	10	1,570	4/83
BGE	Bethlehem Steel Corp.	Sparrows Point, Maryland	Yes	No.6 Oil, Natural Gas, Blast Furnace Gas	150	596,692	7/35
BGE	BRESCO (Baltimore Refuse Energy Systems Co.)	Baltimore, Maryland	Yes	Refuse, with natural Gas	57	253,134	11/84
BGE	Elvin H. Sprouse	Jarrettsville, MD	Yes	Hydro	0.001	4	1/83
BGE	Safe Harbor	Lancaster Co., PA	No	Hydro	277	541,478	1/32- 4/86
DP&L	American Hydro Power Co.	Bay View, MD	Yes	Hydro	0.39	344	5/84
DP&L	Eastern Correctional Institute	Somerset County, MD	Yes	Wood Chips	4.4	16	6/87
PE	AES Warrior Run, Inc.	Cumberland, MD	Yes	Coal	153	108,503	2/00
PEPCO	Georgetown University	Washington, DC	Yes	Coal	2.85	0	11/87
PEPCO	Gude Landfill	Rockville, MD	Yes	Landfill Methane Gas	3.00	17,800	12/85
PEPCO	Montgomery County RRF	Dickerson, MD	Yes	Municipal Waste	52.00	288,430	8/95
PEPCO	Panda Brandywine, L.P.	Brandywine, MD	Yes	Natural Gas/Oil	230.00	528,950	10/96
PEPCO	PG County Detention Center	Upper Marlboro, MD	Yes	Landfill Methane Gas	2.55	4,980	6/87

*Capacity available during peak period.
Source: Ten-Year Plan filings by Maryland utilities for 1999.