PUBLIC SERVICE COMMISSION
OF MARYLAND

TEN-YEAR PLAN
(2009 – 2018)
OF ELECTRIC COMPANIES
IN MARYLAND

Prepared for the
Maryland Department of Natural Resources
In compliance with Section 7-201
of the Maryland Public Utility Companies Article
February 2010

State of Maryland
Public Service Commission

6 St. Paul Street
Baltimore, MD 21202
Tel: (410) 767-8000
www.psc.state.md.us

This report was drafted by the Commission's Integrated Resource Planning Division (Michael Lee, Director) in cooperation with the Demand Side Management Division (Crissy Godfrey, Director), the Electricity Division (Phillip VanderHeyden, Director) and the Engineering Division (Jerry Hughes, Chief Engineer). Electric companies under the Commission's jurisdiction provided most of the data in the Appendix.

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LIST OF ACRONYMS AND DEFINITIONS USED

A&N	A&N Electric Cooperative
ACEEE	American Council for an Energy Efficient Economy
AMI	Advanced Metering Infrastructure
AP / PE	The Potomac Edison Company d/b/a Allegheny Power
Berlin	Town of Berlin
Blueprint Plan	Blueprint for the Future Plan
BGE	Baltimore Gas and Electric Company
BRAC	Base Realignment and Closing Commission
BTU	British thermal unit
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CCM	Capacity Credit Market
CEG / Constellation	Constellation Energy Group
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CFL	Compact Fluorescent Light bulbs
Choptank	Choptank Electric Cooperative
CIS	Customer Information System
CO_2	Carbon Dioxide
COMAR	Code of Maryland Regulations
Commission / MD PSC	Public Service Commission of Maryland
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CSA	Construction Service Agreement
CSP	Curtailment Service Providers
CWIP	Construction Work in Progress
D.C.	District of Columbia
DFAX	Distribution factors
DG	Distributed Generation
DNR	Department of Natural Resources (Maryland)
DOE	Department of Energy
DPL / Delmarva	Delmarva Power and Light Company
DR	Demand Response (or Resource)
DRI	Demand Response Initiative
DSM	Demand Side Management
DSRWG	Demand Side Response Working Group
Easton	Easton Utilities Commission
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EIA	Energy Information Administration
Electric Act	Electric Customer Choice and Competition Act of 1999
EMAAC	Eastern Mid-Atlantic Area Council
EMS	Energy Management System
EPA	Environmental Protection Agency

EPAct	Energy Policy Act
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESA 2007	Energy and Security Act of 2007
ESP	Electro-Static Precipitator
ETR	Estimated Time of Restoration
EVA	Economic Value Added
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization (System)
FRR	Fixed Reserve Requirement
FTR	Financial Transmission Right
GATS	Generation Attributes Tracking System
GIS	Geographic Information System
GW/GWh	Gigawatt/Gigawatt-hours
HAA	Healthy Air Act
Hagerstown	Hagerstown Municipal Electric Light Plant
Hg	Mercury
HVAC	Heating, Ventilation, and Air Conditioning
HVDC	High Voltage Direct Current
HVCS	High Volume Call Service
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-Owned Utility
IRM	Installed Reserve Margin
ISA	Interconnection Service Agreement
ISO	Independent System Operator
ISO-NE	ISO-New England
IVR	Interactive Voice Response
kV	Kilovolt
kW/kWh	Kilowatt/Kilowatt-hours
LDA	Load Deliverability Area
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MACRUC	Mid-Atlantic Conference of Regulatory Utilities Commissions
MADRI	Mid-Atlantic Distributed Resources Initiative
MAPP	Mid-Atlantic Power Pathway
MBR	Market-Based Rate
MDE	Maryland Department of the Environment
MDM	Meter Data Management System
MDS	Mobile Dispatch System
MEA	Maryland Energy Administration
MERTT	Maryland Electric Reliability Tree Trimming (Council)
MISO	Midwest Independent (Transmission) System Operator
MMU	Market Monitoring Unit (PJM)

MOU	Memorandum of Understanding
MW/MWh	Megawatt/Megawatt-hours
NERC	North American Electric Reliability Council
NIETC	National Interest Electric Transmission Corridors (DOE)
NIST	National Institute of Standards and Technology
NOx	Nitrogen Oxides
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OA	Operating Agreement (PJM)
OATT	Open Access Transmission Tariff (PJM)
ODEC	Old Dominion Electric Cooperative
OFA	Over Fire Air
OMS	Outage Management System
OPC	Office of People's Counsel (Maryland)
OPSI	Organization of PJM States, Inc.
PATH	Potomac-Appalachian Transmission Highline
PE / AP	The Potomac Edison Company d/b/a Allegheny Power
Pepco	Potomac Electric Power Company
PHI	Pepco Holding, Inc.
PJM	PJM Interconnection, LLC (Pennsylvania-Jersey-Maryland)
PJM-EIS	PJM – Environmental Information Systems, Inc
PPRP	Power Plant Research Program
PSC	Public Service Commission
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act (of 1978)
PV	Photo-voltaic
QF	Qualifying Facility
REC	Renewable Energy Credit
RFC	Reliability First Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
ROE	Return on Equity
ROW	Right-of-Way
RPM	Reliability Pricing Model (PJM)
RPPWG	Regional Planning Process Working Group
RPS	Renewable Energy Portfolio Standard
RPS Legislation	PUC Article § 7-701 *et seq.*
RTEP	Regional Transmission Expansion Plan
RTEP	Regional Transmission Expansion Planning Protocol
RTO	Regional Transmission Organization
SACR	Selective Auto-Catalytic Reduction
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCR	Selective Catalytic Reduction

SERC	Southeast Reliability Council
SMECO	Southern Maryland Electric Cooperative, Inc.
SO_2	Sulfur Dioxide
Somerset	Somerset Rural Electric Cooperative
SOS	Standard Offer Service
SPP	Southwest Power Pool
Staff	Technical Staff of the Maryland PSC
SWMAAC	Southwest Mid-Atlantic Area Council
TEAC	Transmission Expansion Advisory Committee (PJM)
Ten-Year Plan	Ten-Year Plan of Electric Companies in Maryland
Thurmont	Thurmont Municipal Light Company
TrAIL	Trans-Allegheny Interstate Line
TRC	Total Resource Cost
TWG	Technical Working Group
Williamsport	Town of Williamsport
WMS	Work Management System

I. INTRODUCTION

Section 7-201 of the Public Utility Companies Article, *Annotated Code of Maryland*, requires the Maryland Public Service Commission ("Commission" or "PSC" or "MD PSC") to forward a Ten-Year Plan to the Secretary of Natural Resources on an annual basis. This report constitutes that effort for the 2009-2018 timeframe, and the referenced data and information is as it existed as of December 31, 2009. It is a compilation of information on long-range plans of Maryland electric utilities. This report also includes summaries of events that have or may affect the electric utility industry in Maryland in the near future.

A principle focus of the Commission is the reliability of Maryland's electricity supply. Achieving reliability is a complex undertaking requiring a consideration of factors which affect both supply and demand. To address the elements affecting reliability the Commission, as detailed in this report, is taking action on several fronts: challenging wholesale power policies at the Federal Energy Regulatory Commission ("FERC"); working with the wholesale market monitor to effectuate positive market results; evaluating the need for procuring new generation in the State; directing new utility investment in demand response programs to reduce peak electricity demand; evaluating conservation and energy efficiency programs to meet EmPower Maryland peak and energy reductions;[1] and encouraging better use of emergency generation within the State to promote adequate, economical and efficient delivery of electricity services.

Section II of this plan addresses the peak demand load forecast for Maryland and establishes the baseline load requirements for the next ten years. **Section III** provides information on generation, including certificates of public convenience and necessity ("CPCNs"), and forecasts the availability of generation to meet load requirements. **Section IV** reviews transmission issues impacting Maryland including the Department of Energy's National Interest Electric Transmission Corridors. **Section V** addresses the options for energy efficiency, conservation, and demand response as part of Maryland's supply resources and discusses the effort required to meet the Governor's "EmPower Maryland" goals. Proposals to deploy advanced metering are also discussed in this section. As the environment continues to play an increasingly important role in energy decisions, **Section VI** discusses climate change, Maryland's involvement in the Regional Greenhouse Gas Initiative, and issues involving the growth of renewable generation. **Section VII** provides information on distribution reliability, the manner in which utilities have managed outages and how they plan to meet load requirements.

Beginning with **Section VIII**, we broaden our perspective and review Maryland's Electricity Market in general terms and its relation to Commission efforts that are currently underway or anticipated. **Section IX** discusses PJM and the impact that market rule changes have had both regionally and in Maryland. **Section X** reviews national issues and the impact generated by FERC rulings and the Department of Energy actions. Also included in the Ten-Year Plan is an Appendix that contains a compilation of data provided by Maryland's utilities summarizing, among other things, demand and sales anticipated over the next 15 years.

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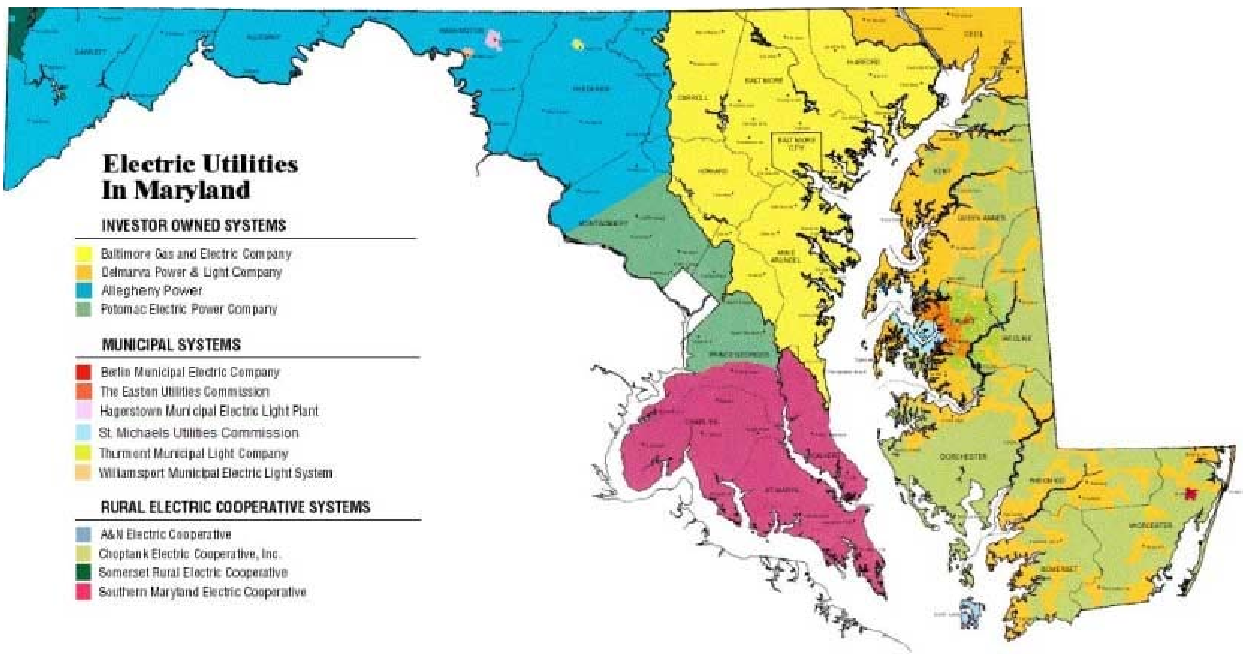
[1] EmPower Maryland Energy Efficiency Act of 2008, Chapter 131, Laws of Maryland, which amended § 7-211 of the Public Utility Companies Article.

The Maryland energy service territory is geographically divided among thirteen electric utilities. Four of the largest are investor-owned utilities ("IOUs"), four are electric cooperatives (two of which serve only small areas of Maryland) and five are electric municipal operations.[2] Table A-1 in the Appendix lists the utilities providing retail electric service in Maryland and Map I.1 below provides a geographic picture of the utilities' service territories.

Map I.1: Maryland Utilities and their Service Territories in Maryland



II. MARYLAND UTILITY AND PJM ZONAL LOAD FORECASTS

A. Introduction

The foundation of an analysis for meeting Maryland's electricity needs starts with a forecast of the anticipated demand over a relevant planning horizon. The Commission evaluates forecasts from individual utilities, and also the PJM regional forecasts that provide separate estimates for transmission zones as shown in Figure II.A.1.

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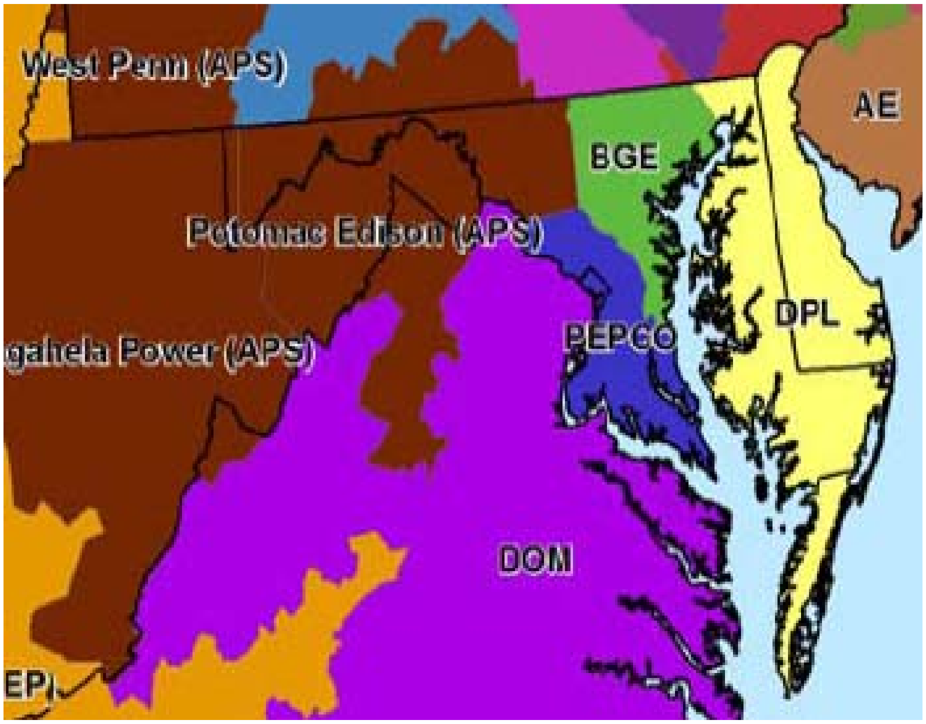
[2] The St. Michaels Utilities Commission service territory was transferred to Choptank Electric Cooperative, Inc. in October 2006.

Figure II. A.1. PJM Maryland Forecast Zones



Source: PJM Interconnection

PJM sub-regions, known as zones, generally correspond with the investor-owned utility ("IOU") service territories, while also including municipal and rural electric cooperatives.[3] The four IOUs operating in Maryland are Baltimore Gas and Electric Company ("BGE), Potomac Electric Power Company ("Pepco"), Delmarva Power and Light Company ("DPL"), and The Potomac Edison Company d/b/a Allegheny Power ("AP" or "Allegheny"). PJM zones for three of the four IOUs traverse state bounds and extend into other jurisdictions providing multiple states with efficiency and reliability gains through resource sharing. Pepco, DPL and AP company data are a subset of the PJM zonal data, since PJM's zonal forecasts are not limited to Maryland. The BGE zone, alone, resides strictly within the State of Maryland.

PJM operates the wholesale power market that includes the entire mid-Atlantic region and dispatches power plants to serve load on an economic bid basis, subject to transmission capacity availability. Because the PJM forecasts impact electric consumer prices at the retail level, the Commission closely monitors the development of PJM regional forecasts.

While forecasts can rely on similar economic data, projection of peak demand and energy usage can vary based upon the underlying assumptions used to generate the forecasts. In general, the expected growth in peak demand and electricity usage is due primarily to expected increases in population and economic activity, which have a direct impact on electricity consumption levels. Key forecast variables include economic and non-economic variables. Economic variables used in forecast models can include gross domestic product, employment,

[3] The PJM service territory spans all or parts of 13 states and the District of Columbia.

energy prices, and population. Non-economic variables can include weather normalized variables, monthly seasonal variables, ownership of appliances, and building codes.

The Commission continues to monitor and review the peak demand and energy sales forecasts of PJM for each transmission zone serving Maryland. A review of economic data suggests that the recession will be deeper and longer than previously estimated. In addition to the recessionary impact, EmPower Maryland and DSM efforts will play an integral role in reducing future electricity demand in Maryland. The DSM efforts will also have a large impact in reducing the system-side peak demand in Maryland, and the surrounding region as a whole. The combination of the recession and DSM activities has served to lower the growth rate of expected peak demand in relation to forecasts generated last year. Last year's forecasted annual growth rate of peak day demand net of DSM activities was 0.73 percent for the period. The current year forecast of peak demand growth net of DSM activities is 0.3 percent for the forecast period ending 2023 [see Table A-5(b)].

B. PJM Zonal Forecast

The PJM 2010 Load Forecast Report includes long-term forecasts of peak loads and net energy for the entire wholesale market region and each PJM sub-region (i.e. zone) – including the four sub-regions in which Maryland resides.[4] The 2010 Load Forecast Report concludes that the PJM region will in aggregate experience higher peak usage in the summer throughout the forecast period ending 2025.[5] PJM expects annual average summer peak PJM growth of 1.7 percent for the next ten year period and 1.5 percent for the fifteen year forecast horizon. Tables II. B. 1 and 2 present comparisons in expected growth for the four PJM zones containing Maryland.[6] The 2010 Load Forecast is compared to the 2009 Load Forecast on a very broad macro level for the four PJM regions roughly corresponding with the four IOU service territories that serve Maryland. When compared, the 2010 and 2009 PJM Load Forecasts are consistent for two zones – BGE and Pepco – while there is a significant downward revision to the forecast of DPL, which serves Maryland, Delaware, and Virginia. The PJM zones containing BGE, DPL and Pepco experience their peak demands during the summer while the PJM region containing APS experiences peak demands in the winter.

Table II.B.1. Summer Peak Load (MW) Growth Rates

PJM Zone	2009-2019*	2010-2020**
APS	1.5%	1.4%
BGE	1.8%	1.8%
DPL	2.1%	1.4%
Pepco	1.2%	1.2%

4 PJM, PJM Load Analysis Subcommittee, Available: http://www.pjm.com/committees-and-groups/subcommittees/las.aspx

5 The current forecast reflects an increase over the prior forecast of 244 MW (0.2 percent) for 2013 and 709 MW (0.5 percent) for 2015, respectively.

6 For Maryland, the four PJM regions contain all four of the State's investor-owned utilities, the five municipal systems; as well, Maryland's four rural electric cooperatives.

Table II.B.2. Winter Peak Load (MW) Growth Rates

PJM Zone	2009-2019*	2010-2020**
APS	1.3%	1.3%
BGE	1.0%	1.1%
DPL	1.5%	1.0%
Pepco	1.1%	1.2%

Sources: * PJM Load Forecast Report, January 2009.
** PJM Load Forecast Report, January 2010.

C. Maryland Company Forecasts

The Maryland electric utilities annually submit responses to Commission data requests that include forecasts of peak and annual energy demand. The information provided by each company is summarized in the Appendices as Tables A-5(a-d). Data requests for the current Ten-Year Plan include responses that expand beyond a ten year period – from 2009 through 2023. The prior year submissions began and terminated one year earlier, that is, from 2008 through 2022. A comparison of the electric utility submissions for the two years is provided to indicate, on an aggregate basis, current expectations for reduced peak usage in the State for electricity; as well, a reduction in overall State consumption levels. The utility forecasts reflect short-term recessionary impacts, the utilities' current expectations with regards to nascent demand-side management ("DSM") and energy efficiency programs, and the expected reductions in energy usage attributable to these programs. Precision and certainty diminish the longer the time period over which a forecast is generated. Comparisons are first presented for the state in aggregate for four common future years: 2010, 2015, 2020, and 2022.[7] Additional analysis pertaining to 2010 and the ten year period starting in 2010 to 2020 are also explored.

Table II.C.1 compares Maryland peak demand forecasts on an aggregate basis and includes utility provided estimates of currently approved DSM and energy efficiency measures. Maryland utility estimates for last year are labeled "2009 Ten Year Plan," and utility estimates for the current report are labeled "2010 Ten Year Plan." Peak demand forecasts for this report compared to last year indicate that peak demand is estimated to decrease by 3.9 percent in 2010, after which -- with continuing implementation of the current suite of utility-sponsored demand reducing programs -- overall peak demand for the State is projected to decrease by approximately 9 percent in the subsequent years[8]

[7] Additional data for the 2009 to 2023 period can be located in the Appendix. Corresponding data considering the 2008 to 2022 time period can be located in last year's Ten Year Plan.

[8] Reductions are a comparison strictly to last year's submissions and are not considered on a per-capita basis in keeping with the goals of EmPower Maryland.

Table II.C. 1 Comparison of Maryland Peak Demand Forecasts (Net of DSM Programs; MW)

Year	2009 Ten Year Plan	2010 Ten Year Plan	Reduction	%
2010	**14,479**	**13,913**	**-566**	**-3.9%**
2015	**14,495**	**13,162**	**-1,333**	**-9.2%**
2020	**15,600**	**14,181**	**-1,419**	**-9.1%**
2022	**16,064**	**14,623**	**-1,441**	**-9.0%**

Sources: PSC, Ten-Year Plan (2008-2017) of Electric Companies in Maryland, and PSC Ten-Year Plan (2009-2018) of Electric Companies in Maryland.

Table II.C.2 compares utility forecasted energy sales within the State of Maryland. When compared to utility estimates provided last year, the electric utility forecasts in aggregate project additional reductions in overall annual electricity sales in the State. During the timeframe examined, reductions in energy usage trend downward between two and three percent when compared to last year's electric utility submissions. The results in Table II.C.1 pertaining to peak demand, and the results in Table II.C.2. pertaining to usage can be used in tandem to broadly suggest that the lower the demand in relation to usage, the greater the potential in utilizing lower cost resource options to satisfy future year retail sector loads.[9] Demand-side management efforts that reduce peak usage play a direct role by which electrical energy is being used in Maryland.

Table II.C.2 Comparison of Maryland Energy Sales Forecast (Net of DSM Programs; GWh)

Year	2009 Ten Year Plan	2010 Ten Year Plan	Reduction	%
2010	65,631	64,246	-1,386	-2.1%
2015	68,872	67,457	-1,415	-2.1%
2020	74,211	72,178	-2,033	-2.7%
2022	76,394	74,187	-2,208	-2.9%

Sources: PSC, Ten-Year Plan (2008-2017) of Electric Companies in Maryland, and PSC Ten-Year Plan (2009-2018) of Electric Companies in Maryland.

Additional comparison between the prior year Ten Year Plan utility submissions and this year's submissions are presented in Table II.C.3 for the State's forecasted peak demands, Submissions for last year are labeled "2009 Ten Year Plan," and this year is labeled "2010 Ten Year Plan." The comparisons are provided for a ten year period using the 2010 and 2020 forecast years – rather than the extend time horizons presented for electricity sales in the prior tables. The table presents gross and net peak demand; as well, the difference in capacity (i.e. MWs). Moreover, the table present the forecasted increase (i.e., change) in peak demand expected with DSM implementation. The table indicates the utilities in aggregate forecast

[9] In states requiring utilities to submit resource plans for Commission review, a load factor analysis is a useful initial benchmark. The load factor is the ratio of average demand to the maximum or peak demand over a given time period - typically one year. In general, a higher load factor can lower the average cost of serving customers by increasing the usage of lower cost resources and using these resources more efficiently.

slightly less peak demand growth over the time period examined; as well, robust reductions in peak demand growth as a result of DSM and energy conservation measures.

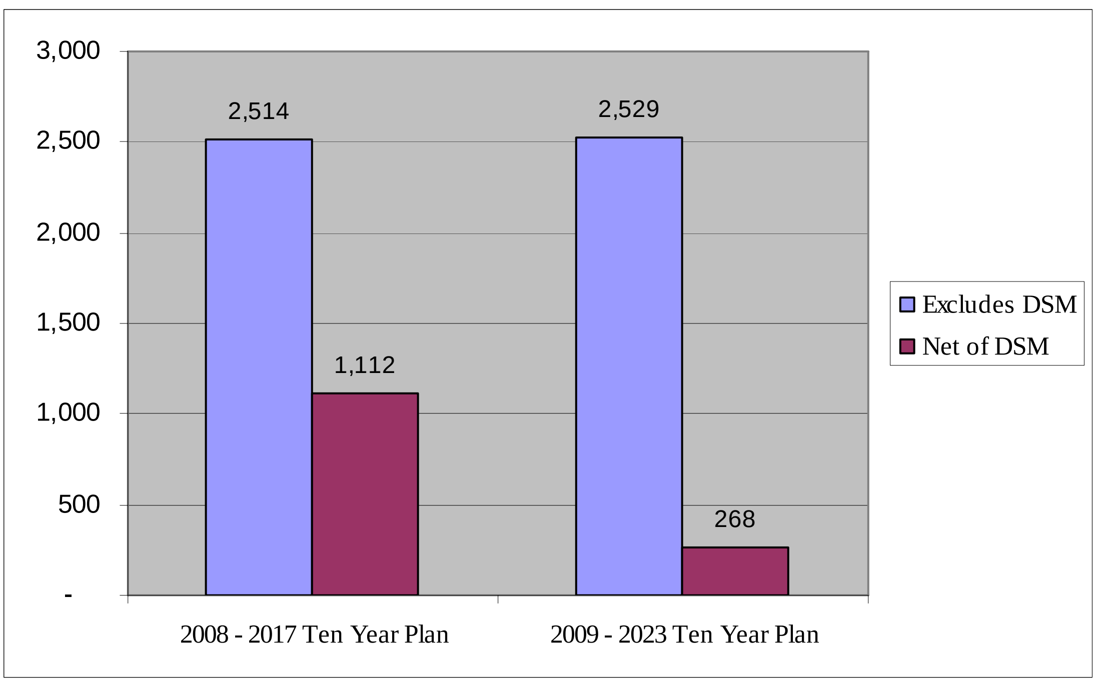
Table II.C.3: Maryland Peak Demand Forecast Comparisons (MW)

Forecast year	2009 Ten Year Plan				2010 Ten Year Plan		
	Gross of DSM	Net of DSM	Difference		Gross of DSM	Net of DSM	Difference
	A	B	C = A-B		D	E	F = D - E
2010	15,289	14,461	828		14,764	13,913	851
2020	17,803	15,573	2,230		17,293	14,181	3,112
Change	2,514	1,112	1,402		2,529	268	2,261

Sources: PSC, Ten-Year Plan (2008-2017) of Electric Companies in Maryland, and PSC Ten-Year Plan (2009-2018) of Electric Companies in Maryland, Tables A-5(b) and A-5(d).

The information contained in Table II.C.3 is illustratively presented as Figure II. C. 1 below. The figure suggests that the utilities' estimates in gross peak demand remains relatively stable between the two annual submissions (2,514 MW compared to 2,529 MW); however, the utilities now project additional reduction in the growth of peak demand attributable to the effectiveness of the utility DSM programs. Prior year utility estimates gauged the effectiveness of utility DSM programs to reduce peak demand by 1,402 MW (2,514 Gross Demand – 1,112 Peak Demand). This year, the utilities indicate the growth in total state peak demand will be significantly smaller: 268 MW – an overall expected reduction of 2,261 MW (2,529 Gross Demand – 268 Peak Demand).

Figure II.C. 1: Maryland Peak Demand Forecast Comparisons: Aggregate Growth 2010 to 2020 (MW)



Sources: PSC, Ten-Year Plan (2008-2017) of Electric Companies in Maryland, and PSC Ten-Year Plan (2009-2018) of Electric Companies in Maryland, Tables A-5(b) and A-5(d).

III. REGIONAL GENERATION AND SUPPLY ADEQUACY IN MARYLAND

A. Introduction

The Commission recognizes that in order to maintain electric system reliability and an adequate supply of electricity for customers in the future, access to adequate electric capacity must be available to meet customer demand.

A critical requirement for reliable electric service is an appropriate level of generation and transmission capacity to meet Maryland consumers' energy needs. While reliability needs may be partially met through local demand side management programs and the import of low-cost electricity using high-voltage transmission lines, local generation must be maintained and is essential to keep the lights on and the power grid operating effectively and economically. All load serving entities in the PJM region are required to ensure they have sufficient capacity contracts to provide reliable electric service during periods of peak demand. As of 2008, Maryland's net summer generating capacity was 12,486 megawatts ("MW"). Maryland's peak demand forecast for 2010 with utility demand-side management and energy conservation measures is approximately 13,900 MW (13,913 MW). Providing an estimate for an appropriate reserve margin of an additional 2,157 MW, [10] would result in estimated reliability requirement of 16,070 MW. Therefore, nearly 3,600 MWs (3,584 MW) of estimated capacity in the transmission system serves to meet Maryland's requirements during periods of peak usage in the system.

All major utility systems in the eastern half of the United States and Canada are interconnected and operate synchronously as part of the Eastern Interconnection. PJM operates, but does not own, the transmission systems in (1) Maryland, (2) all or part of 12 other states, and (3) the District of Columbia. With FERC approval, PJM undertakes this task in order to coordinate the movement of wholesale electricity and provide access to the transmission grid for utility and non-utility users alike. Within the PJM region, power plants are dispatched to meet load requirements without regard to operating company boundaries. Generally, adjacent utility service territories import or export wholesale electricity as needed to reduce the total amount of installed capacity required by balancing retail load and generation capacity over a regional, diversified system.

[10] The example uses an installed reserve margin (IRM) of 1.155 for 2010/2011, which is applicable for planning reserves on regional basis for the entire pool of PJM resources. IRM establishes a level of installed capacity resources that will provide acceptable reliability levels for the PJM region – and not on an individual state basis. Capacity resources are procured with available unforced capacity from existing generation and also considers the probability of a generating unit will not be available (i.e., Equivalent Demand Forced Outage Rate, EFORd). See PJM, Resource Adequacy Planning, 2009 PJM Reserve Requirements Study, Table I - 1: Historical RRS Parameters, p. 3, Available: http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-reserve-requirement-study.ashx

Maryland, Delaware, New Jersey, Virginia, and the District of Columbia continue to be net importers of electricity. Maryland imported about 29% of its electricity in 2007. On a percentage basis, Maryland was the fourth largest electric energy importer in the United States – surpassed by the District of Columbia, Virginia, and Delaware. (Table III.A.1). Much of the East Coast is dependent on generation exported from states to the west of the region – many with low-cost, largely depreciated, coal-fired generation assets. Prominent states in the region currently exporting more electricity in aggregate than is consumed are Pennsylvania, West Virginia, and Kentucky.

Table III.A.1: State Electricity Imports

State	Retail Sales (Consumption)	Sales + T & D Loss *	Generation	Net Imports	Percentage of Sales Imported
D.C.	12,110,185	13,078,999	75,251	13,003,749	99.4%
Virginia	111,569,552	120,495,116	78,360,507	42,134,609	35.0%
Delaware	11,868,810	12,818,314	8,534,163	4,284,152	33.4%
Maryland	65,390,660	70,621,912	50,197,924	20,423,989	28.9%
New Jersey	81,934,334	88,489,080	62,671,245	25,817,836	29.2%
Tennessee	106,716,934	115,254,288	95,113,409	20,140,880	17.5%
Ohio	161,770,827	1,747,124	155,155,545	19,556,948	11.2%
New York	148,177,523	160,031,724	145,878,687	14,153,038	8.8%
N. Carolina	131,880,754	142,431,214	130,115,301	12,315,913	8.7%
Kentucky	92,404,100	99,796,428	97,225,319	2,571,109	2.6%

Source: EIA, Electricity: U.S. Data 2007, April 2009.
Note: * T & D losses are assumed to be 8%. All figures are in MWh.

B. Maryland Generation Profile: Age and Fuel Characteristics

Most electric generating capacity in Maryland is provided by coal-fired power plants, which contribute approximately 40% of the summer peak capacity available in-state. The vast majority of the State's coal-fired generation capacity (nearly 70%) is provided by power plants 30 or more years old. However, Maryland's larger coal-fired generating units are being retrofitted to comply with Maryland's Healthy Air Act (See Section III.B.) and continue operating. The only units built within the last thirty-five years are the two Brandon Shores plants (646 and 643 MW, 1984 and 1991) and the AES Warrior Run plant (180 MW, 1999). The other major coal facilities in Maryland include Morgantown (1,492 MW); Chalk Point (2,428 MW); Dickerson (853 MW); H.A. Wagner (1,007 MW); and C.P. Crane (399 MW). Approximately 40% of all capacity in Maryland burns oil or gas as a fuel source, and the majority of these facilities are aging. Overall, only 22% of the State's summer generating capacity has been constructed in the past twenty years and only 7% in the last ten years as indicated in Table III.B.1.

Table III.B.1: Maryland Generating Capacity Profile

	Capacity		Age of Plants, by % of Fuel Type			
Primary Fuel Type	**Summer (MW)**	**Pct. of Total**	**1-10 Years**	**11-20 years**	**21-30 years**	**31+ years**
Coal	4,958	39.7%	3.6%	13.0%	13.6%	69.8%
Dual-fired*	3,066	24.6%	2.3%	35.7%	18.7%	43.4%
Nuclear	1,735	13.9%	0.0%	0.0%	0.0%	100.0%
Other Gas	1,236	9.9%	57.4%	0.0%	0.2%	42.6%
Petroleum	766	6.1%	1.4%	2.5%	0.2%	95.8%
Hydroelectric	590	4.7%	0.0%	0.0%	0.1%	99.8%
Other & Renewables	135	1.1%	12.2%	40.9%	47.1%	0.0%
TOTAL	**12,486**	**100%**	**7.3%**	**14.9%**	**10.7%**	**67.1%**

Source: EIA, EIA-860 2007, April 2009 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/maryland.html).
*Dual-fired plants primary fuel types: 66.07% Oil; 33.93% Gas.
Due to rounding, figures may not add to total shown.

While no generating facilities in Maryland are scheduled for retirement, a few of the older generating units in the PJM region have requested deactivation. These older generating units are located at six different sites in four Mid-Atlantic jurisdictions: Delaware, Pennsylvania, New Jersey and the District of Columbia. These older generation units have typically operated only a limited number of hours each year and generate electricity at relatively high marginal costs. However, the units may also be helpful in ensuring reliable electric service in the region. PJM undertakes an analysis to determine the parameters under which units may deactivate or continue to operate.[11]

In 2007, owners of power plants requested deactivation of units at three locations in either Delaware or D.C.: two Indian River units (Delaware) with a combined capacity of 179 MW; two Buzzard Point plants (D.C.), 250 MW; and two Benning site power plants, 550 MW (D.C.). The reliability issues have been identified and are expected to be resolved.[12] Depending on the unit, deactivation has been requested between May of 2010 through May of 2012.

In 2009, owners of power plants requested deactivation of units at three locations in New Jersey and Pennsylvania: two Cromby units (Pennsylvania) with a combined capacity of 109 MW; two Eddystone units (Pennsylvania), 98 MW, and two units at the Kearny site, 250 MW. Although these units have requested deactivation between May of 2011 and June of 2012, the current PJM reliability analysis has determined that one of the Cromby units and one of the Eddystone units must continue to operate.

Although no significant generation has been constructed in Maryland within the past few years, the Commission has granted several CPCNs (discussed in Section III.C.) and no units have retired. The Gould Street plant (101 MW), located in the BGE zone was deactivated in

11 PJM, Manual M-14D: Generator Operational Requirements, Revision: 17, effective date January 1, 2010, Available: http://www.pjm.com/~/media/documents/manuals/m14d.ashx

12 PJM, Planning, Generation Retirements, Generation Retirement Summaries, Pending Deactivation R Requests, Available: http://www.pjm.com/planning/generation-retirements/gr-summaries.aspx

2003, until being reactivated in June 2008. Coal generation plants owners are also installing new SO_2 scrubbers on their existing units in Maryland to continue operating while complying with the Maryland Healthy Air Act. Mirant Corp has already installed scrubbers on three of its coal-fired power plants and have plans to install scrubbers in four more units totaling 2,473 MW capacity, which will be a multiyear effort to reduce SO_2 emissions in Maryland. Similarly, Constellation is already operating its two new Brandon Shore scrubbers with the second plant being returned to service on March 1, 2010. These coal power plants equipped with scrubbers will be able to use less expensive, high-sulfur Appalachian coal fuel stocks.

Table III.B.2: Maryland Electric Power Generation Profile (2007)

Source	**MWh**	**Share (%)**
Coal	29,699,186	59.2
Nuclear	14,353,192	28.6
Oil & Gas	3,603,318	7.2
Hydroelectric	1,652,216	3.3
Other & Renewables	890,012	1.7
Total	**50,197,924**	**100**

Source: EIA, April 2009 (http://www.eia.doe.gov/cneaf/electricity/st_profiles/maryland.html).

The Maryland generating profile differs considerably from its capacity profile. Coal and nuclear facilities generate almost 90% of all electricity produced in Maryland, even though they represent little more than half of in-state capacity. In contrast, oil and gas facilities, which tend to operate as mid-merit or peaking units, coming on line only when needed, generate less than 10% of the electricity produced by in-State resources, while representing approximately 40% of in-State capacity. Table III.B.2 summarizes Maryland's in-State fuel-mix in MWh by generating sources for 2007. In 2007, Maryland plants produced 50,197,924 MWh of electricity.

The total summer capacity of Maryland generators is 12,486 MW, and over 80% of the in-state generation capacity is owned by two companies: Constellation Energy Group and Mirant. Constellation Energy Group owns 43% of this capacity, and Mirant owns 38%. On an individual basis, no other company owns more than a 5.0% share of the capacity sited in-state. Nearly two-thirds (65%) of the State's power plant capacity resides in one of four counties: Anne Arundel, 18%; Calvert, 14%; Charles, 12%; and Prince Georges, 21%. Table III.B.3 lists Maryland generating units by owner, county, and capacity.

Table III.B.3: Generation by Owner, County, and Capacity

Owner Name/Plant Name	County	Capacity Statistics (MWs)		
		Nameplate	Summer	Pct.
A & N Electric Coop/Smith Island	Somerset	1.7	1.6	0.013
AES Warrior Run Inc/AES/Warrior Run Cogen F	Allegheny	229	180	1.442
Allegheny Energy Supply Co LLC/R. Paul Smith	Washington	109.5	115	0.921
Alternative Energy Associates/Brighton Dam	Montgomery	0.5	0.5	0.004
Berlin MD (Town of)/Berlin	Worcester	9	9	0.072
Brookfield Asset Management Inc/Deep Creek	Garrett	20	18	0.144
ConEd Inc./Rock Springs Generating Facility	Cecil	772.6	632	5.063
CEG/Calvert Cliffs Nuclear Power Plant	Calvert	1828.7	1735	42.983
CEG/Brandon Shores	Anne Arundel	1,370	1,283	
CEG/C P Crane	Baltimore	415.8	378	
CEG/Gould Street	Baltimore City	103.5	101	
CEG/Herbert A Wagner	Anne Arundel	1,058.5	963	
CEG/Notch Cliff	Baltimore	144	120	
CEG/Perryman	Harford	404.4	370	
CEG/Philadelphia Road	Baltimore City	82.8	64	
CEG/Riverside (MD)	Baltimore	257.2	237	
CEG/Westport	Baltimore City	121.5	116	
Easton Utilities/Easton; Easton 2	Talbot	72.4	69	0.552
Exelon Corp./Conowingo	Harford	506.8	572	4.581
Florida Crystals Corp./Domino Sugar Baltimore	Baltimore City	20	20	0.160
MD Dept of Pub Safety & Corr Svc/Eastern Corr Inst	Somerset	5.8	4.6	0.037
MeadWestvaco Corp (The)/Luke Mill	Allegany	65	60	0.481
Mirant Corp/Chalk Point	Prince Georges	2,647	2,417	38.138
Mirant Corp./Dickerson	Montgomery	930	853	
Mirant Corp/Morgantown Generating Station	Charles	1,548	1,492	
Mittal Steel Co. N V/Sparrows Point	Baltimore	120	152	1.220
NRG Energy Inc./Vienna	Dorchester	183	170	1.362
Panda Energy Intl Inc/Panda Brandywine LP	Prince Georges	288.8	230	1.842
Pepco Holdings Inc/Crisfield	Somerset	11.6	10	0.104
Pepco Holding Inc/Eastern Sanitary Landfill	Baltimore	3	3	
Prince Georges County/Brown Station Road I and II	Prince Georges	6.7	6	0.045
TriGen Cinergy Sol. Balto/Inner Harbor East Heat	Baltimore City	2.1	2	0.0331
TriGen Cinergy Sol. Balto/Millennium Hawkins Pt.	Baltimore	10.5	7	
Trigen Cinergy Sol. College Park/UMCP CHP Plant	Prince Georges	27.4	20	
Trigen Cinergy Sol. Sweetheart Cup/Owings Mills	Baltimore	11.2	11	
Waste Energy Partners LP/Waste Energy Partners LP	Harford	1.2	1	0.009
Waste Management/Wheelabrator Baltimore Refuse	Baltimore City	64.5	61	0.491
Worcester County Renewable	Worcester	1	0.9	0.007
Total		13,454.7	12,486	**100%**

Source: EIA - Form 860, April 2009. (Due to rounding, figures may not add to total shown).

C. Potential Generation Additions in Maryland

Siting for Maryland generation continues to be an important concern. There are reliability, environmental, and competitive issues that must be resolved while finding an appropriate location for a new generator. With generation largely deregulated and currently the responsibility of independent power producers, siting has tended to be limited to the expansion of existing sites. Generation companies have proposed various projects, but they are typically either expansions of existing sites or conjoined locations with other industrial or government facilities. Without the financial assurances that were typically available through utility ownership, it has become increasingly difficult for all but the major generation companies to select potential new sites and secure the funding necessary to build new generation and secure long-term sales contracts.

Other sources of generation have benefited from the Commission's small generation interconnection rules. Distributed generation from solar facilities and combined heat and power installations are examples of small scale generation. Co-locating smaller generation facilities with other industrial process facilities provides an alternative to increasing central station generation capacity.

However, regardless of the growth in distributed generation, there will still be a need for central power stations that can be acceptably developed. Areas in or near the State that may be considered for new generation include off-shore wind projects in the Atlantic Ocean and along the Eastern Shore, the Nanticoke River area around Vienna on the Lower Eastern Shore, the Calvert Cliffs area in Southern Maryland, various brownfield sites in the Central Maryland area, and wind power sites in the mountains of Western Maryland. Upgrades and additions to existing sites (i.e., brownfield deployment) offer advantages over new, undeveloped greenfield sites with respect to licensing, transmission facilities, and environmental concerns.

During the last five years, the Commission has granted several CPCNs for generating projects in Maryland. When and if constructed, the electricity generated by these projects will be available for Maryland and the PJM region.

In late 2008 and during 2009, the Commission received one CPCN application and two CPCN exemption applications, totaling approximately 240 MW in new generation. CPCN and CPCN exempt projects in queue total 3,235 MW for new generation and another 186 MW of reactivated generation (Case Nos. 8938, 8939, 9124, 9127, 9129, 9132, 9136, 9164, 9191, and 9199). In 2008 and 2009, four CPCN applications and three CPCN exemptions were approved. Case No. 8938 approved a CPCN exemption; Case No. 8939 granted an extension; Case No. 9124 approved to re-activate a generating station; Case No. 9127 was approved on June 26, 2009; Case No. 9129 was approved; Case No. 9132 approved to re-activate a generating station; Case No. 9136 is currently in progress; Case No. 9191 granted a CPCN exemption on November 18, 2009; and Case No. 9199 is currently in progress. These projects are described in more detail below according to the docketed case number.

- Case No. 8938: Exemption of the CPCN requirements approved October 29, 2008. Clipper Windpower filed a CPCN application for 101 MW of wind powered energy.

The CPCN was approved in March 2003, but the wind facility was not built and the CPCN expired. In January 2008, Clipper—under the name Criterion Power Partners—filed a CPCN Exemption for 70 MW of wind powered energy. Criterion was the first applicant to utilize newly enacted legislation allowing a generating station that produces electricity from wind to be exempted from the CPCN process if the capacity of the wind generating station does not exceed 70 MW.

- Case No. 8939: Approved March 20, 2003. Savage Mountain Wind Force, LLC filed a CPCN application on August 30, 2002 for the construction of 40 MW wind generation facility located at the boundary of Allegany and Garrett Counties in Western Maryland. The CPCN would have expired in March of 2008; however, Savage Mountain filed a motion for an extension of the five year deadline for completion of construction of the wind generation facility. On September 5, 2007, the Commission granted a modification of the original application and extended the deadline to commence construction to no later than March 20, 2010.
- Case No. 9124: Approved February 15, 2008. Constellation Energy Group ("Constellation") filed to re-activate the Gould Street generating station, which was retired in 2003 due to equipment failure. The gas-fired generator will be rebuilt to provide 101 MWs of capacity, and the proposed facility is scheduled for commercial operation in 2016.
- Case No. 9127: Approved June 26, 2009. UniStar Nuclear Energy, LLC and UniStar Nuclear Operating Services, LLC filed a joint CPCN application on November 13, 2007, to construct a third unit at the existing Calvert Cliffs Nuclear site. With a nameplate capacity of approximately 1,710 MWs, the proposed nuclear unit is designed to provide base load generation in Maryland and would equal the capacity of the two existing Calvert Cliffs units. The proposed facility is scheduled to begin commercial operation in 2016. The Combined Operating License application is under review by the Nuclear Regulatory Commission ("NRC"). Moreover, the NRC has initiated the Environmental Impact Statement ("EIS") with plans to release a draft for public comment in early 2010.
- Case No. 9129: Approved November 8, 2008. Competitive Power Ventures plans to have a 645 MW gas-fired plant in Charles County. A CPCN was previously granted to Free State Electric, LLC for a project on this site known as Kelson Ridge in 2001 (See Case No. 8843). The project was originally permitted for 1,200 MW, but the CPCN was relinquished on December 6, 2002, and the plant was not constructed.
- Case No. 9132: Approved May 10, 2008. On December 27, 2007, Constellation filed a CPCN application to reactivate Unit 5 at the Riverside Generating Station, which was taken out of service in 1993. The unit will operate exclusively as a natural gas-fired unit and provide up to 85 MW of additional capacity. The current rated generating capacity at the Riverside State is 261 MW.
- Case No. 9136: In Progress. On January 29, 2008, Constellation filed a CPCN application for the expansion of the Perryman Generating Station at the Harford County, Maryland site. The application represents 600 MW of additional capacity over the existing 355 MW.

- Case No. 9164: Exemption of the CPCN requirements approved on March 12, 2009. On November 5, 2008, Dans Mountain Wind Force, LLC filed a CPCN Exemption application for the construction of a 69.6 MW wind generation facility in Frostburg, Maryland. According to the Dans Mountain project developer U.S. Wind Force, the new zoning regulations in Allegany County will restrict the envisioned 25 turbine project to a single turbine, unless a special exemption is granted by the County.[13] As a result, the project is on hold while U.S. Wind Force reviews future development and legal options.[14]
- Case No. 9191: Exemption of the CPCN requirements approved on November 18, 2009. On April 21, 2009, Synergics Roth Rock Wind Energy, LLC filed a CPCN Exemption application for a 50 MW wind generation facility to be located in Garrett County. A wholesale purchase power agreement was executed between Roth Rock and Delmarva Power & Light Company on May 30, 2008. The project is expected to be in-service by October 2010.
- Case No. 9199: In Progress. Energy Answers International, Inc. filed an application on May 22, 2009 for a CPCN to construct a 120 MW renewable fuel fired power plant located at the former site of the FMC Corporation facility in Baltimore City. On July 28, 2009 the Commission granted a waiver of the two-year notice requirement of filing an application before construction can commence.

13 Email conversation between Staff and David Friend, VP Marketing and Sales for U.S. Wind Force, LLC on October 9, 2009.

14 Ibid.

Table III.C.1 identifies all proposed generating projects for which the Commission has recently granted or received an application to grant a CPCN.

Table III.C.1: New Generating Resources Planned for Construction in Maryland

Resource Developer And Location	Capacity & Fuel	Expected In-Service Date	Interconnected w/PJM?	CPCN Status
Criterion Power Partners, LLC., Garrett Co.	70 MW Wind	4th Qtr. 2010	Yes	CN 8938 Exemption Granted 10/29/2008
Savage Mountain US Wind Force LLC, Allegany and Garrett Cos.	40 MW Wind	(Suspended)	Yes	CN 8939 Granted 3/20/2003
Gould Street, Constellation Energy, Baltimore City (reactivation)	101 MW Gas	2016 Reactivation	Yes	CN 9124 Granted 2/15/2008
UniStar (Constellation Energy), Calvert Co.	1,710 MW Nuclear	2016	Yes	CN 9127 Granted 6/26/2009
Competitive Power Ventures, Charles Co.	645 MW Gas	4th Qtr. 2010	Yes	CN 9129 Granted 11/8/2008
Riverside, Constellation Energy, Baltimore Co. (reactivation)	85 MW Gas	2nd Qtr. 2010	Yes	CN 9132 Granted 5/10/2008
Perryman, Constellation Energy, Harford Co. in Allegheny County	600 MW Gas/Oil	120 - 240 MW by June 2010 600 MW by 2014	Yes	CN 9136 In Progress
Dan's Mountain Wind Force Allegheny County	69.6 MW Wind	(Suspended)	Yes	CN 9164 Exemption Granted 3/12/09
Synergics Wind Energy, Roth Rock Windpower Project, Garrett Co.	50 MW Wind	4th Qtr. 2010	Yes	CN 9191 Exemption Granted 11/18/2009
Energy Answers International, Inc. Baltimore City	120 MW Municipal Solid Waste	3rd Qtr. 2012	Yes	CN 9199 In Progress

Additional projects are listed for Maryland in the PJM queues in various stages of the study process. PJM queued projects include projects powered by wind, natural gas, and landfill gas. Some queued projects are below 70 MWs and do not require CPCNs. Other projects less than 20 MWs represent additions to existing plants or commitment of behind the meter generation to sell power to the grid.

D. PSC Activities: Harnessing Additional Resources

The Commission instituted Case No. 9149 on August 13, 2008 to address a potential reliability "gap" beginning in 2011. On November 6, 2008, the Commission recognized that securing demand response from existing or readily installable emergency load response was the lowest risk and likely lowest cost solution to the potential reliability shortfall. The Commission ordered the four investor-owner utilities ("IOUs") to develop and issue "Gap RFPs" to meet the requirements of PJM's Emergency Load Response Program for the planning years 2011-2016, in order to mitigate potential impacts of a delay in the projected in-service dates of the approved TrAIL and proposed PATH transmission lines. The Commission also directed Staff to convene a distributed generation work group for the purpose of determining the scope of potentially available distributed generation resources and proposing a methodology to harness those resources that are not currently participating in PJM's Emergency Load Response Program.

On March 11, 2009, the Commission ordered the IOUs to execute contracts for the following total MW of demand response capacity for the specified planning years based on the competitive responses of Curtailment Service Providers to the Gap RFP:

Table III.D.1: Contracted MWs of Demand Response

Planning Year	2011/2012	12/13	13/14	14/15	15/16	16/17	17/18
AP Total Capacity	67.8	67.8	67.8	67.8	17.8	N/A	N/A
BGE Total Capacity	171.0	171.0	171.0	156.0	11.0	11.0	11.0
DPL Total Capacity	54.5	54.5	54.5	42.5	7.5	N/A	N/A
Pepco Total Capacity	107.3	107.3	107.3	77.3	17.3	7.0	7.0
Total MW Capacity	400.6	400.6	400.6	343.6	53.6	18.0	18.0

The Commission Staff observed that prices bid into the Gap RFP fell roughly into three groups. The first group of bids at a comparatively low price would yield a total of 105.6 MW of capacity for each of the first three bid years. In contrast, the highest priced bids would have added only 111.1 MW of capacity to the totals in the above table, but total estimated cost would increase by 2/3. The Commission concluded that the cost for the 400.6 MW of total capacity "insurance" outlined above was small relative to the reliability value of that capacity in the event of a capacity shortfall.

During the winter and spring of 2009, Staff convened the Distributed Generation Work Group ("DG WG") as directed by the Commission to discuss longer term issues related to distributed generation resources. The DG WG failed to reach a consensus on all issues. The Staff May 12, 2009 report on the DG WG contained the following conclusions and recommendations:

- The Commission's policy on distributed generation should facilitate broader economic deployment of efficient customer-owned resources such as combined heat and power ("CHP") and seek to maximize the participation of emergency generation in demand response programs.
- Based on Staff's analysis, at least 400 MW of emergency generation that currently does not participate in PJM emergency demand response programs could potentially participate in those programs.
- Recent changes in air quality regulations permit unlimited operation of emergency generation during PJM emergencies.
- Prior to the first DG WG meeting knowledge among customers and the distributed resources industry of the new air quality, regulations appeared quite limited. Although basic awareness of the options now available to emergency generator owners has now improved, more still needs to be done to inform generation owners and demand response aggregators.
- The Commission's small generator interconnection regulations do not appear to be a barrier to customer-owned generation participation in demand reduction or electricity sales opportunities.
- According to the American Council for an Energy-Efficient Economy, CHP has the potential to provide 291 MW of demand reductions and 2,000 GWh of annual energy savings in Maryland which is over 10 percent of the total statewide EmPOWER Maryland demand reductions and 17 percent of the energy savings required in 2015.
- Some utility standby tariffs can act as barriers to otherwise economic CHP installations.
- This Report recommends standby service principles including definitions, service options and availability, and rate components that would be used in a formal rulemaking for standby service statewide.
- Natural gas utility distribution service rates often do not recognize the high load factors possible for many CHP applications. Principles related to load factor recognition including rulemaking, rate proceeding and interim high load factor rider implementation alternatives are presented in this Report.
- CHP and other alternative energy customer side resources could contribute significantly to the achievement of EmPOWER Maryland demand reduction and energy saving targets, and one or more programs for these CHP and other customer side resources should be included in utility energy efficiency and conservation portfolios. This Report presents principles to be followed by the utilities for the development of these programs.

The Commission held a hearing on the DG WG report and comments of the parties on July 9, 2009. A decision is pending.

E. CPCN Exemptions for Generation

Pursuant to Section 7-207.1 of the Public Utility Companies Article, certain power generation projects are exempted from the Certificate of Public Convenience and Necessity process. Section 7-207.1 became effective October 1, 2001, and was modified effective October 1, 2005. More recently, a wind-generating station category with an opportunity for public comment was added to the section – effective July 1, 2007. Section 7-207.1 approvals may be granted to generating stations designed to provide on-site generated electricity and meeting the following qualifications:[15]

1. The capacity of the generating station does not exceed 70 MW; and
2. The electricity that may be exported for sale from the generating station to the electric system is sold only on the wholesale market pursuant to an interconnection, operation, and maintenance agreement with the local electric company.[16]

For wind-powered generating stations with a capacity up to 70 MW, there are two additional qualifications that must be met in order to be granted a CPCN exemption. The first is that the generating station must be land-based, so any off-shore facility will be required to seek full CPCN authorization. The second qualification is that the Commission must provide an opportunity for public comment at a public hearing.

The Commission's CPCN exemption application requires the applicant to select one of four specific types of generating stations: Type I, Type II, Type III, or Type IV. With the exception of Type I, all generators are required to obtain an Interconnection, Operation and Maintenance Agreement ("Interconnection Agreement") with the local Electric Distribution Company ("EDC"). Type I generators must obtain a letter from the local EDC that states an Interconnection Agreement is not necessary.

A Type I generator is not synchronized with the local electric company's transmission and distribution system and will not export electricity to the electric system.[17] An emergency or back-up generator is the most common Type I generator. A Type II generator is synchronized

[15] Section 1-101(s) of the Public Utility Companies Article defines "On-site generated electricity" as electricity that: (1) is not transmitted or distributed over an electric company's transmission or distribution system; or (2) is generated at a facility owned or operated by an electric customer or operated by a designee of the owner who, with the other tenants of the facility, consumes at least 80% of the power generated by the facility each year.

[16] The statute also provides for an exemption for a generating station that does not exceed 25 MWs if electricity that may be exported for sale from the generating station to the electric system is sold only on the wholesale market pursuant to an interconnection, operation, and maintenance agreement with the local electric company and at least 10% of the electricity generated at the generating station each year must be consumed on-site.

[17] Section 1-101(h) of the Public Utility Companies Article defines "Electric company," with certain exclusions, as a person who physically transmits or distributes electricity in the State to a retail electric customer.

with the electric system; however it will not export electricity to the electric system. Generators used for peak-load shaving or generators participating in a demand response program are the most common form of Type II generators. Type III generators are synchronized with the electric system and export electricity for sale on the wholesale market. A Type IV generator is a generator that is synchronized with the electric system, but utilizes the disconnect feature of an inverter to prevent export of power in the event of a power failure on the utility's grid. Type IV generators are capable of "net-metering", but cannot sell electricity on the wholesale markets.

Table III.E.1. provides an overview of the type, number, and capacity of generators that have applied for CPCN exemptions on an annual basis. The number of applications has been consistently increasing over time, and these generators have a cumulative generation capacity of almost 1 GW.

Table III.E.1: CPCN Exemptions Granted, Since October 2001[18]

Period Approved	**Applications**	**No. of Units**	**Total MWs**
Calendar Year 2002	18	42	114.8
Calendar Year 2003	20	28	42.5
Calendar Year 2004	33	51	66.9
Calendar Year 2005	36	70	94.4
Calendar Year 2006	31	55	91.4
Calendar Year 2007	40	62	67.3
Calendar Year 2008*	72	129	212.1
Calendar Year 2009	100	143	213.0
Total	**350**	**580**	**902.3**
Pending	5	13	15.5
Total (Including Pending)	**355**	**593**	**917.8**

*In October 2008, a 28 turbine, 70 MW wind generating facility was approved. The facility is included in the 2008 total, but installation is not expected to be completed until 2010.

For the generators granted CPCN exemptions, Table III.E.2, on the next page, presents additional information pertaining to CPCN classification type, fuel source, capacity, and number of units. Diesel units account for 62.7 percent of the CPCN exemption capacity (575.6 MW); wind, 15.2 percent (139.6 MW); natural gas, 10.6 percent (97.7 MW); oil, 8.4 percent (77.5 MW); biomass, 2.7 percent (25.1 MW), and solar, 0.3 percent (2.3 MW).

18 Current through December 31, 2009.

Table III.E.2: Generators by Type and Fuel (December 31, 2009)

CPCN Exemption	Fuel Source	Total MW	No. of Units
Type I	Diesel	543.5	469
	Natural Gas	39.3	15
	Oil	47.5	51
Total		**630.3**	**535**
Type II	Diesel	32.1	19
	Natural Gas	40.4	9
	Oil	26	9
	Biomass	3.32	5
Total		**101.9**	**42**
Type III	Natural Gas	18	4
	Oil	4	2
	Biomass	21.8	3
	Wind	139.6	2
Total		**183.4**	**11**
Type IV	Solar	2.3	5
Total		**2.3**	**5**
TOTAL TYPE I - IV		**917.8**	**593**

Numbers may not total due to rounding.

In order to obtain an approval under Section 7-207.1 of the Public Utility Companies Article, an applicant must submit a completed application. In addition, the generator will need a wholesale sales agreement with PJM if the generator is selling electricity on the wholesale market. It is important to note that the approval does not exempt an applicant from obtaining all other necessary state and local permits and regulations, for example, those required by the Air and Radiation Management Administration at the Maryland Department of the Environment ("MDE").

F. Maryland's Healthy Air Act and Generation Upgrades

Pursuant to the Healthy Air Act of 2006 ("Healthy Air Act" or "HAA"), Constellation and Mirant implemented methods for emissions control at their Maryland coal-fired plants. Maryland's total generating capacity within the State is nearly 12,500 MW, and coal fired generation currently provides almost 40 percent of the power. In accordance with meeting the January 1, 2010 deadline of the HAA, Maryland's larger coal-fired generating units have being retrofitted with wet scrubbers for the control of sulfur dioxide and selective catalytic reduction systems for the control of nitrogen oxides. However, Constellation has determined that this was not cost-effective for the Crane and Wagner plants, so only the Brandon Shores units have both of these controls.

Constellation plans to use low-sulfur coal with reagents and sorbents for the reduction of emissions of mercury and sulfur dioxide (“SO_2”) at both the Crane and Wagner plants. Constellation obtained permission from the Commission to conduct test burns to evaluate emissions and performance of the plants with the use of various combinations of coals, sorbents and reagents. Some plants have sought CPCNs for modifications such as barge unloading facilities to accommodate the delivery and processing of limestone and different types of coal (Morgantown, Crane, and Wagner). The evaluations will assist Constellation and the State agencies in their determination of the efficacy of the process and whether or not more testing needs to be done. A summary of plant modifications for compliance with the HAA follows.

The newly constructed flue gas desulfurization systems (“FGD”) are now operational on Mirant’s Chalk Point, Dickerson, and Morgantown coal-fired power plants. Mirant also recently installed selective catalytic reduction systems (“SCR”) on three of the coal-fired units at its Chalk Point and Morgantown generating stations. Together the FGD and SCR systems can reduce SO_2, nitrogen oxide (“NOx”), and mercury to meet the air quality mandates of the HAA. Selective non-catalytic reduction systems (“SNCR”) are operational on units 1, 2, and 3 at the Dickerson power plant to control NOx emissions.

For HAA compliance, Constellation recently installed scrubbers on units 1 and 2 of its Brandon Shores power plant. Based upon the permitted testing, Constellation has implemented SNCR as the NOx control technology at the Crane and Wagner facilities and has completed performance testing. For mercury controls, both plants have selected to use halogenated activated carbon injection systems and performance testing is currently in progress. Constellation continues testing SO_2 control options at Crane and Wagner.

Constellation is expected to continue experimenting with alternate fuels and process alterations at Crane and Wagner in order to ensure a reliable generating process that complies with the HAA. Large quantities of sorbents and reagents may be required to reduce emissions to acceptable limits at the coal plants. Based on preliminary studies, between four and twenty tons of sorbent per hour per unit may be required. This material will be captured in the downstream particulate control equipment as fly ash. The additional accumulations of fly ash will require disposal and will be a factor in evaluating the cost of the pollution controls. Testing of alternate reagents and sorbents will enable Constellation to determine a cost-effective way to comply with the Healthy Air Act.

The table below lists the relevant case numbers for each coal plant and summarizes the generating capacity, existing emissions controls, and the retrofits proposed for HAA compliance. Existing emissions controls at some of the plants include electrostatic precipitators (“ESP”), FGD, SCR, SNCR, and low NOx burners with overfire air (“OFA”).

Table III.F.1: Emission Related Upgrades for Coal-fired Plants

Power Plant/ Owner	Relevant Case Numbers	Generating Capacity	Existing Emissions Controls	Retrofits for Healthy Air Act Compliance
Dickerson/ Mirant	CN9087 CN9140	853 MW total; 3 coal units total 546 MW	FGD, Low NOx burners with OFA, ESP, fabric filters	FGD & SNCR (Units 1, 2, & 3)
Chalk Point/ Mirant	CN9079 CN9086	2,400 MW total; 2 coal units total 700 MW	FGD, SCR, Low NOx burners with OFA, ESP, SCR (Unit 2)	FGD (Units 1 & 2), SCR (Unit 1), sorbent
Morgantown/ Mirant	CN9031 CN9085	1,492 MW total; 2 coal units total 1,244 MW	FGD, SCR, Low NOx burners with OFA, ESP, SCR	Delivery of coal by barge, FGD, SCR, sorbent
Brandon Shores/ Constellation	CN9075	2 units total 1,370 MW	FGD, SCR, Low sulfur coal, ESP	FGD (>$500M), sorbent for Hg & SAM, fabric filter
Crane/ Constellation	CN9084 CN9206	Unit 1: 190 MW Unit 2: 209 MW	Fabric filter for particulates at both units	Low sulfur coal, sorbents (powdered activated carbon) for Hg; SNCR for NOx
Wagner/ Constellation	CN9083	Unit 2: 136 MW Unit 3: 359 MW	ESP, SCR (unit 3)	Low sulfur coal, sorbents (powdered activated carbon) for Hg; SNCR for NOx (Unit 2) (<$10M)

IV. TRANSMISSION INFRASTRUCTURE: NATIONAL, PJM AND MARYLAND

A. Introduction

Transmission facilities in PJM and Maryland have continued to play a key role in energy supply. With Maryland's dependence on energy imports, it is necessary that adequate transmission facilities be available to reliably provide electricity supplies. While all network systems can experience congestion at times, portions of the Mid-Atlantic States -- including central Maryland and the Delmarva Peninsula have continued to experience significantly higher levels of congestion than the rest of PJM. This, in turn, can lead to higher energy and capacity costs in portions of Maryland and the surrounding States since local, but potentially more expensive, generation resources must be employed. Adequate capacity and reliable supplies of electricity are continually monitored, managed, and when necessary supplemented with additional infrastructure.

B. Eastern Interconnection Planning Collaborative

The United States Department of Energy ("DOE") has launched an initiative to develop regional transmission plans.[19] Maryland and PJM are participating in these programs. The program takes into account the input of a larger base of stake holders and a broader geographic region including all interconnections east of the Rocky Mountains. Maryland participates in the Eastern Interconnection Planning Collaborative ("EIPC"). These initiatives are in the formative phases and it will be some time before recommendations are made.

On December 18, 2009, DOE announced that EIPC would receive $16 million in stimulus funding. Fourteen million dollars was also awarded and allocated to the states to support the Eastern Interconnection States' Planning Council ("EISPC"). DOE and FERC also plan to coordinate efforts related to interconnection-level electric transmission planning. DOE will lead electricity-related research and development activities, including research and demonstrations for hardware and software technologies that help operate the country's transmission networks. FERC will continue to oversee electricity reliability standards nationally and will enforce regulations to ensure that all transmission planning happens in an open, transparent and non-discriminatory manner.

C. The Regional Transmission Expansion Planning Protocol

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of the wholesale market operator, PJM. PJM implements this function pursuant to the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of the PJM Operating Agreement.

PJM annually develops the Regional Transmission Expansion Plan ("RTEP") to meet system enhancement requirements for new backbone transmission lines and interconnection requests for new generation. To establish a starting point for development, PJM performs a "baseline" analysis of system adequacy and security. The baseline is used for conducting feasibility studies on behalf of all proposed generation and transmission projects. Subsequent System Impact Studies for those potentially viable projects provide recommendations that become part of the RTEP Report.

PJM's RTEP looks at a 15 year projection of the grid to predict reliability problems. The system is planned for the probability of loss of load to be one day in ten years. Single contingency analysis allows for the grid to function with the loss of any one line. In some cases double contingency analysis is used. PJM's 15-year planning horizon process has predicted that the congestion on the eastern and western interfaces may cause both load deliverability and

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[19] American Recovery and Reinvestment Act of 2009 (H.R. 1, pages 24-25)

generator deliverability issues in central Maryland.[20] Deliverability issues can be a result of significant load growth and the retirement of existing generation.[21] Ideally, these problems can be solved with a combination of new generation, transmission projects, and demand response.

The RTEP Process applies reliability criteria over a fifteen-year horizon to identify transmission constraints and reliability concerns. PJM uses CETO/CETL[22] analysis to determine the import capabilities of the transmission system to supply the peak load requirements for sub-regions within PJM. There are currently 23 sub-regions or load deliverability areas ("LDA") in PJM. The Transmission Expansion Advisory Committee ("TEAC") is the primary forum for stakeholders to discuss the RTEP results. The Maryland Public Service Commission is an active participant in the RTEP and regularly attends the TEAC meetings.

1. Baseline Reliability Assessment

PJM establishes a baseline from which the need and responsibility for transmission system enhancements can be determined. PJM performs a comprehensive load flow analysis of the ability of the grid to meet reliability standards, taking into account forecasted loads, imports and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and generation retirements. The baseline reliability assessment identifies areas where the planned system is not in compliance with standards required by NERC[23] and the regional reliability councils. The baseline assessment develops and recommends enhancement plans to achieve compliance.

2. Inter-regional Planning

PJM is engaged in planning processes that address issues of mutual concern to PJM and neighboring transmission grid systems: the Midwest ISO, ISO New England, the New York ISO, and with the Tennessee Valley Authority. The Inter-regional Planning Stakeholder Advisory Committee facilitates stakeholder review and input into the Coordinated System Plan. Coordinated regional transmission expansion planning across seams is expected to reduce congestion on an inter-RTO basis, and enhance the physical

[20] The central Maryland area of the Mid-Atlantic generally includes northern Virginia and the Baltimore/Washington region.

[21] Generation slated for retirement includes Benning Road and Buzzard Point in Washington, DC., and Indian River on the Eastern Shore.

[22] Capacity Emergency Transfer Objective/ Capacity Emergency Transfer Limit.

[23] Since 1968, the North American Electric Reliability Corporation (NERC) has been committed to ensuring the reliability of the bulk power system in North America. To achieve that goal, NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; audits owners, operators, and users for preparedness; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC). As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. NERC's status as a self-regulatory organization means that it is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical and efficient practices.

and economic efficiencies of congestion management. Inter-regional ties are a benefit for reliability, especially when load centers peak at different times (referred to as load diversity). Forums such as this have been important for addressing problems such as loop flows around Lake Erie.

3. Obligation to Build RTEP Projects

PJM's Transmission Owners' Agreement obligates transmission owners to proceed with building transmission projects that are needed to maintain reliability standards as approved by the PJM Board of Directors. Transmission owners can voluntarily build these projects or PJM can file with FERC to request FERC to order the project to be built. In Maryland, Certificates of Public Convenience and Necessity ("CPCN") are required for transmission lines above 69,000 volts or modifications to existing facilities.

4. PJM's Authority

FERC approved PJM as an Independent System Operator in 1997. Since that time, PJM has administered its RTEP as described in Schedule 6 of the Operating Agreement. PJM has subsequently received authority from FERC for procedures and rules for transmission expansions needed to enable the interconnection of new and expanded generation and merchant transmission facilities (1999). PJM has amended the RTEP to include the development of transmission projects to support competition in wholesale electric markets, allowing them to justify projects for economic reasons as well as reliability.

PJM received final approval as a FERC approved Regional Transmission Operator ("RTO") in 2002. As an RTO, PJM is the administrator of the Open Access Transmission Tariff ("OATT") as approved by FERC. The OATT is the basis for PJM to collect charges to recover the costs of projects owned, constructed, or financed by the transmission owners. Transmission owners file rate schedules with FERC to recover transmission investments made pursuant to the RTEPs approved by the PJM Board. The OATT enables generation to be sold anywhere in the system.

D. Transmission Congestion in Maryland

1. PJM's Definition of Congestion

PJM's Locational Marginal Pricing ("LMP") system takes account of congestion in determining electricity prices. It reflects the value of the energy at the specific location and time it is delivered. Theoretically, if the lowest-priced electricity could simultaneously be distributed across the entire 13 states and the District of Columbia, which encompass the PJM wholesale market, prices would be the same across the entire PJM grid. However, the extensive capital investments which would be required for such an expansive transmission system preclude such a free flow movement of electricity throughout the region. Therefore, more-expensive but advantageously located power plants that generate electricity are required to meet the demand. Congestion costs vary rapidly during the course of a day, seasonally, and from year-to-year. As a result, LMPs are higher for the congested area and lower at the source of cheaper power.

Persistent patterns of high LMPs can indicate future reliability problems and the need for new generation, new transmission, and/or demand response.

2. Planning for Congestion Control

One constraint accounted for over a quarter of total congestion costs in 2008 and the top five constraints accounted for nearly two-thirds of total congestion costs. The AP South interface displaced the Bedington-Black Oak Interface as the largest contributor to congestion costs in 2008 due to system upgrades on the Bedington-Black Oak circuit in December 2007 and the associated redefinition of the AP South interface on September 1, 2008.

The Bedington-Black Oak constraint has been a persistent source of large congestion costs for several years[24], but decreased in both congestion costs and frequency in 2008. The AP South interface is now the primary west to east transfer constraint.

3. Costs of Congestion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Total congestion costs increased by $271 million or 15 percent, from $1,846 billion in calendar year 2007 to $2.117 billion in calendar year 2008. Congestion in Maryland was $298 million in 2007 and $296 million in 2008. As of August 2009, congestion costs in Maryland for 2009 have been about 30% lower.

Zone	Total Annual Zonal Congestion Costs ($ million) [25]
Allegheny Power	$487.1
Baltimore Gas & Electric	$92.9
Delmarva Power	$96.4
Potomac Electric Power	$215.9

Wholesale prices for electricity are determined in PJM's Reliability Pricing Model ("RPM") Base Residual Auctions. Blocks of capacity are sold regionally for future delivery. The data below summarizes the capacity price for Maryland in 2012/2013.[26]

24 The 500 kV Bedington to Black Oak line was responsible for $711.3M or 38.7% of PJM's total congestion in 2007. Allegheny installed a Static VAR Compensator (SVC) at Black Oak substation in Dec of 2007. Together with a Mt. Storm-Pruntytown 500 kV upgrade and various other transformers and breakers, the capacity of this line has been increased. However, congestion will continue to be a problem until TrAIL and PATH are built.

25 Data for 2008. The zones for Allegheny, and PHI include territory outside of Maryland (Delaware, District of Columbia, Pennsylvania, New Jersey, West Virginia, Virginia)

26 Presented to MADRI July 1, 2009. Data also found on the PJM website.

Zone	$/MW-day
Western Maryland (APS)	$16.46
Central Maryland (BGE & Pepco)	$133.46
Delmarva (DPL)	$169.63
Delmarva South	$222.30

Transmission expansion for the bulk electric system can act to reduce the differences from zone to zone and support reliability requirements and economic concerns.

Financial Transmission Rights ("FTRs") and Auction Revenue Rights ("ARRs") give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy market across the specific FTR transmission path. In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of LMP on April 1, 1998. The total of ARR and FTR revenues hedged 97.4% of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period and 97.2 percent of the congestion costs in PJM in the first seven months of the 2008 and 2009 planning period.[27] For the planning period 2007 to 2008, BGE and Allegheny were hedged at greater than 100%, Pepco at 52.6%, and DPL at 19.8%.

The Baltimore/Washington area is in a situation where the congestion of the electricity transmission grid continues to warrant attention. However, overall congestion during the summers of 2008 and 2009 was not as pronounced as it has been in previous years. This has been primarily due to reduced demand with no significant generation or transmission outages. The PJM metered peaks for 2008 and 2009 were lower than the peaks in 2007 and 2006. This was due to the relatively mild weather, the slowing economy, and more diversity (non-coincident regional peaks).

On May 15, 2009, PJM announced an increase in Demand Resources ("DR") of 5,682 MWs for the 2012/2013 capacity auction. A total of 67% of the DR cleared in constrained regions, reflecting its value in helping to reduce congestion. The combined results of the six capacity auctions have seen 27,640 MWs of new resources that would not have been available without RPM.

[27] The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues, or those paying congestion premiums. The FTR markets can be risky and have resulted in defaults for some participants. Financial entities own about 70 percent of all Monthly Balance of Planning Period FTRs.

E. Proposals for New High Voltage Transmission Lines in PJM

On October 15, 2009, the PJM Interconnection Board authorized an additional $1.4 billion in electric transmission system additions and upgrades throughout the grid that serves 51 million people in 13 states and the District of Columbia. Determined via PJM's RTEP process, the upgrades are required to support reliable electricity flows and ensure the power supply system meets national standards through 2024. The upgrades authorized by the PJM Board since 2000, including the most recent approvals, total more than $14.7 billion in investment.

According to PJM, its regional plan reaffirmed the need for several backbone transmission line projects that the board previously had authorized to address power supply problems:

- Trans-Allegheny Interstate Line (TrAIL), 502 Junction to Loudon. Construction is well under way on TrAIL, and it will be in service in 2011. This 500-kilovolt ("kV") transmission line will run from near the border of Pennsylvania and West Virginia to northern Virginia. Two hundred ten miles are in Allegheny Power's service territory and 30 miles are in Dominion's service territory. Its estimated cost is $970 million.

- Potomac-Appalachian Transmission Highline ("PATH") is a 765-kV transmission line that will extend 300 miles from the Amos Substation (Charleston, WV.) to the Kemptown Substation in Frederick County, Maryland. The estimated cost is $1.8 billion. This project is docketed as Case No. 9198 at the MD PSC.

- Mid Atlantic Power Pathway Project ("MAPP") is a 500-kV line that will connect the Possum Point Substation in Virginia and the generation plants in southern Maryland to Indian River and Vienna on the Delmarva Peninsula. The portion under the Chesapeake Bay will be a submarine high-voltage DC line ("HVDC"). The MAPP project is expected to improve reliable service on the Delmarva Peninsula and increase import capabilities in central Maryland. This project is docketed as Case No. 9179 at the MD PSC.

- Susquehanna to Roseland is a 500-kV line, approximately 130 miles from northern Pennsylvania to northern New Jersey.

According to PJM, these transmission lines are expected to mitigate congestion along PJM's eastern and western interfaces. The eastern interface consists of four major transmission lines which extend from eastern Pennsylvania and Maryland to New Jersey and Delaware. The western interface consists of four high voltage transmission lines that cross the Allegheny Mountains near western Maryland.

The PJM RTEP requires that cost responsibility for transmission enhancements be established. The cost of transmission facilities in PJM that operate at a voltage of 500 kV and above are socialized across all PJM load. The backbone projects listed above have secured through FERC incentive rate adders.[28] To make this determination, FERC requires the applicant to satisfy the nexus test (non-routine project with advanced technology) and the rebuttable presumption (a project required by PJM). The new interstate transmission lines fall within the National Interest Electric Corridors ("NIETC") established by DOE. The required in-service dates for these projects are subject to change due to PJM's load forecast, which is periodically updated.

In addition to the studies to determine what transmission additions and upgrades are necessary to ensure reliability, the PJM planning process included 195 studies that evaluated the impact of adding new generation on the system. Other transmission projects identified by the transmission owners are listed in Table A-8 of the Ten Year Plan for Maryland. For instance, The Southern Maryland Electric Cooperative is continuing with plans for its 230 kV loop in Southern Maryland. Improvements to the Aquasco to Holland Cliffs portion were approved by the Maryland Commission in 2008. In 2009, the Maryland Commission approved the Holland Cliffs to Hewitt Road segment in Case No. 9136, which includes a portion under the Patuxent River.

V. DEMAND RESPONSE AND CONSERVATION AND ENERGY EFFICIENCY

Demand side management ("DSM"), including various methods of energy efficiency, conservation, demand reduction, and distributed generation, is expected to become an important source of meeting the State's needed supply. DSM supports system reliability, energy security, energy and capacity price mitigation (i.e., reducing overall energy costs), enhanced energy market competitiveness and limits environmental impacts. The Commission encourages energy service providers to offer DSM programs to customers where appropriate. Distribution companies have been tasked with providing cost-effective DSM programs, particularly for mass market residential and small commercial customers. As part of the EmPower Maryland Energy Efficiency Act of 2008 (See PUC Article §7-211) the Commission will require the utilities to implement aggressive and cost-effective demand management and energy conservation programs.

A. Statutory Requirements

Recognizing energy efficiency as one of the least expensive ways to meet growing electricity demands in the State, the EmPower Maryland Energy Efficiency Act ("EmPower Maryland") was enacted on April 24, 2008. By statute, each utility is required to develop and implement cost-effective programs and services that encourage and promote the efficient use and conservation of energy by consumers and utilities alike. EmPower Maryland also establishes long-term target reduction goals for electric consumption and demand, based on a per capita basis and a 2007 energy consumption baseline. The Act specifically states at §7-211(g)(1) and (2):

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[28] For the MAPP project, Pepco received a 12.8 percent return on equity (including incentives); no rehearing sought; as well, BGE was also granted a 12.8 percent return on equity (including incentives); however, rehearing is pending before FERC. The TrAIL project settled for a 12.7 percent return on equity (including incentives). FERC granted PATH a 14.3 percent return on equity (including incentives); however, rehearing remains pending.

(1) To the extent that the Commission determines that cost-effective energy efficiency and conservation programs and services are available, for each affected class (and specifically targeted to low-to-moderate income communities), require each electric company to procure or provide for its electricity customers cost-effective energy efficiency and conservation measures programs and services with projected and verifiable energy electricity savings that are designed to achieve a targeted reduction of at least 5% by the end of 2011 and 10% by the end of 2015 of per capita electricity consumed in the electric company's service territory during 2007; and

(2) Require each electric company to implement a cost-effective demand response program in the electric company's service territory that is designed to achieve a targeted reduction of at least 5% by the end of 2011, 10% by the end of 2013, and 15% by the end of 2015, in per capita peak demand of electricity consumed in the electric company's service territory in 2007.

The Act also states at §7-211(i)(1):

(1) In determining whether a program or service encourages and promotes the efficient use and conservation of energy, the Commission shall consider the: (i) cost–effectiveness; (ii) impact on rates of each ratepayer class; (iii) impact on jobs; and (iv) impact on the environment.

Prior to July 1, 2008, the Act required each utility to consult with MEA regarding the design and adequacy of the programs it was proposing. Each utility is also required to provide an annual update to the PSC and MEA on plan implementation and progress towards meeting the goals. The PSC, in consultation with MEA, must provide an annual report to the General Assembly regarding the status of the programs, a recommendation for the appropriate funding level to adequately fund the programs and services, and the per capita electricity consumption and peak demand for the previous year.

Utilities are required to submit these plans by September 1, for the next three subsequent years[29], with the Commission directed to make its determination by December 31 of that same year whether each utility's initial plans are adequate and cost-effective in reaching the EmPower Maryland goals. The Commission is also required to report its findings to the General Assembly regarding the implementation and success of these programs beginning on or before March 1, 2009 and every year thereafter.

In order for the Commission to monitor the progress and cost-effectiveness of the programs that are offered, the utilities are required to file quarterly and annual reports that detail: the current savings generated by each program; the stages of the program; and the budget for each program by quarter and annually. The quarterly reports are to include program participation levels and expenditures which are to be filed by the end of the month following the calendar quarter end. The annual reports are due to the Commission by January 31 of each year and provide a comprehensive year end report of the previous year's results. The annual reports

[29] This process began September 1, 2008.

are to include a summation of the quarterly reports, as well as year-to-year comparisons, total energy savings, and other information identified by Staff.

In the spring of 2009, Commission Staff also filed and presented a Consensus Report on an Evaluation, Measurement and Verification ("EM&V") plan of the EmPower Maryland programs. This plan included a PSC-directed Independent Evaluator whose role will be to assist in the oversight, quality control and due-diligence of the Utilities EM&V activities as well as to conduct additional State-wide analysis as deemed necessary by the Commission. The utilities and Commission Staff expect to complete the RFP process and commence work by early 2010.

B. Demand Response Initiatives

Demand response is defined as changes in electric usage by end-use customers from their normal consumption patterns either in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices and when system reliability is jeopardized. The increase in electricity prices and changes in technology have spurred interest in finding cost-effective means of reducing electricity consumption. Additionally, the price of electricity in the wholesale markets serving the central and eastern portions of Maryland is determined, in part, by the relative scarcity of generation and transmission capacities serving those areas.

Demand response initiatives comprise utility-run direct load control programs ("DLC"), inclusive of their legacy demand response programs – the precursor of these DLC programs. These programs, although approved separately by the Commission and, in many cases prior to the EmPower Maryland EE&C plans, are a critical component in meeting the EmPower Maryland goals and as such are considered part of the EmPower Maryland umbrella package.

DLC Programs

In 2008, the Commission approved BGE, DPL, Pepco, and SMECO's direct load control programs.[30] Detailed information for the four Commission-approved programs is provided in Section V of the Appendix of the Commission's Ten Year Plan (2008-2017) of Electric Companies in Maryland. Additionally, that Report's Table A-11 provides a side by side comparison of the four DLC programs.

Each DLC program includes these common components: (1) all DLC programs are voluntary; (2) upon receiving a customer request, the utility installs either a programmable thermostat or a direct load control switch for a central air conditioning system or an electric heat pump on a customer's premise; (3) the utilities provide one time installation incentive and bill credits to the participants in the summer peak months; and (4) with the exception of SMECO,

[30] The Commission approved BGE's PeakRewards Program November 30, 2007; Pepco and DPL's EnergyWise Programs on April 18, 2008; and SMECO's CoolSentry Program on April 15, 2008. The utility's filings were documented in Case Number 9111. Potomac Edison/Allegheny Power also filed its direct load control program but it was not found to be cost effective at this time.

customers can choose one of three cycling choices, 50%, 75%, and 100%.[31] Utilities will invoke the cycling process when PJM calls for an emergency event or a utility's determined event during summer peak season. SMECO uses an initial 2 degree offset followed by 30% cycling for the thermostats and a 50% cycling option followed by 30% cycling for the switches during specified time periods. The incentives vary among utilities. The one-time installation incentive is credited to the customer's bill after installation is complete and an annual bill credit is awarded for each participation year. Table V.B.1 summarizes the utilities incentives to the program participants.

Table V.B.1: Utilities Incentive to DLC Program Participants

<table>
<tr><th rowspan="2">Utility</th><th colspan="2">50% Cycling</th><th colspan="2">75% Cycling</th><th colspan="2">100% Cycling</th><th rowspan="2">Bill Credit Month</th></tr>
<tr><th>Installation Incentive</th><th>Annual Bill Credit</th><th>Installation Incentive</th><th>Annual Bill Credit</th><th>Installation Incentive</th><th>Annual Bill Credit</th></tr>
<tr><td>BGE</td><td>$50</td><td>$50</td><td>$75</td><td>$75</td><td>$100</td><td>$100</td><td>Jun. – Sept.</td></tr>
<tr><td>DPL</td><td>$40</td><td>$40</td><td>$60</td><td>$60</td><td>$80</td><td>$80</td><td>Jun.–Oct.</td></tr>
<tr><td>Pepco</td><td>$40</td><td>$40</td><td>$60</td><td>$60</td><td>$80</td><td>$80</td><td>Jun.–Oct.</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="2"></td><td colspan="3">Installation incentive</td><td colspan="3">Annual Bill Credit</td><td rowspan="2">Bill Credit Month</td></tr>
<tr><td>Thermostat</td><td colspan="2">Digital Switch</td><td>Thermostat</td><td colspan="2">Digital Switch</td></tr>
<tr><td>SMECO</td><td>***</td><td colspan="2">None</td><td>$50</td><td colspan="2">$50</td><td>Jun.–Oct.</td></tr>
</table>

*** A participant in SMECO CoolSentry program can keep the installed thermostat for free after 12 months of the installation; otherwise, the thermostat will be removed if the participant terminates the participation less than 12 months.

Table 2 summarizes the progress in installing these devices for each utility DLC program from January through October of 2009. Installed devices (programmable thermostats and digital switches) number 116,036 units. The DLC programs are popular and expected to ramp up in 2010. BGE and SMECO report that there are customer requests pending to install the devices.

[31] The cycling choices of 50%, 75%, and 100% represents the air conditioner compressor working cycle reduced by 50%, 75%, and 100% under PJM or utility invoked emergency events during summer peak season.

Table V.B.2: Utilities Direct Load Program Installation in 2009 (Jan. – Oct.)

Utility	Air Conditioning	
	Installation Numbers	**Pending Order**
BGE	103,758	5,801
DPL	950	n.a.
PEPCO	3,150	n.a.
SMECO	8,178	2,433
Total	116,036	8,234

* n.a. means data are not available.

The DLC program resulted in 852 MW being bid into the PJM for Delivery Year ("DY") 2012-2013 in the May 2009 PJM RPM auction, a 29% increase from 2008 PJM bid of 661.5 MW for DY 2011-2012. To date, these programs have accounted for 2,146 MW of the total capacity bid into PJM market. Table 3 summarizes the capacity bid into PJM's capacity market from the DLC program by utility and delivery year.

Table V.B.3: Direct Load Control Program Bid into PJM BRA (MW)

Utility	DY 2012-2013	DY 2011-2012	DY 2010-2011	DY 2009-2010	Total
BGE[1]	645.5	512.6	415.4	217.0	1,790.4
DPL	37.5	24.7	n.a.	n.a.	62.2
Pepco	144.0	99.2	n.a.	n.a.	243.2
SMECO	25.0	25.0	n.a.	n.a.	50.0
Total	852.0	661.5	415.4	217.0	2,145.8

[1] BGE's bid includes both its current DLC and its legacy demand response program.
* n.a. means data are not available because there was no program launched for these utilities.

The following section provides an update of each of the four programs from January 1, 2009 through October 31, 2009.

1. BGE

BGE launched its DLC program, PeakRewards, in June 2008. Popular to date, PeakRewards has enrolled 71,570 participants and installed a total of 103,758 air conditioning cycling devices from January 1, 2009 through October 31, 2009. BGE is aggressively marketing this program to meet a 50 percent participation goal, or approximately 450,000 customers, by the end of 2011. A total of 135,169 participants are enrolled in the program since its inception, with 145,477 installed devices (thermostats or switches). BGE plans to launch an electric water heater component to its PeakRewards program in the winter of 2010.

BGE also has its legacy demand response programs, which include air conditioner and water heater switches installed in the customer premises, and is in the process of transferring these customers to the PeakRewards program, if the customer decides to continue to participate.

BGE plans to phase out the legacy programs in 2011. Therefore, BGE's bid currently includes both the PeakRewards and legacy demand response programs.

Since the inception of PeakRewards, BGE has bid into PJM's RPM base residual auction ("BRA") for four consecutive delivery years (see Table 3), totaling approximately 1,790 MW of demand reduction.

2. Pepco

Pepco launched its EnergyWise program (similar in program design to PeakRewards) in January 2009[32], planning to install 25,000 air conditioning measures by the end of 2009. As of October 2009, Pepco had installed 3,150 devices due to a longer than expected ramp-up period. As such, this figure has since been revised drastically downward to 5,000 measures by the end of 2009.

Pepco has bid into the last two of PJM's RPM BRAs, with a total bid of 243.2 MW to date. The Company bid 144 MW for DY 2012/2013 into PJM's BRA in May 2009 and 99.2 MW for DY 2011-2012.

3. Delmarva

Concurrently with Pepco, DPL launched its EnergyWise program in January 2009, planning to install 8,100 air conditioning measures. Instead, due to the same delays mentioned in Pepco's program, the Company installed 950 devices by the end of October 2009. DPL has revised its 2009 installation goal to 4,000 measures.

DPL has bid into the last two of PJM's RPM BRA, with a total bid of 62.6 MW. The Company bid 37.5 MW for DY 2012/2013 and 24.7 MW for DY 2011/2012 into the PJM BRA.

4. SMECO

SMECO launched its CoolSentry Program in November 2008. A customer may elect to have installed either a thermostat or a digital switch on his/her air conditioner or electric heat pump. SMECO offers a $50 annual bill credit to each participant, but if a participant chooses to install a thermostat, the participant can also keep the thermostat for free after 12 months of participation. No installation incentive is offered to a participant to choose a digital switch. After prolonged implementation delays, SMECO began ramping up the program in 2009, installing 8,178 measures (thermostat and switches) as of October 2009. This was a considerable increase from its 276 installed measures in the last two months of 2008. Currently, SMECO is the process of transitioning its legacy customers to its new CoolSentry Program, as they so elect.

SMECO estimated the load reduction from the CoolSentry was 49.9 MW for DY 2011-2012 and 52.4 MW for DY 2012-2013. However, SMECO bid only 25 MW in PJM's BRA for the aforementioned delivery year.

[32] Pepco and DPL entered into a contract with Comverge on January 20, 2009 and started the testing phase with its own employee volunteers.

Peak Load Reduction Forecast

Responses to the Commission's Ten-Year Plan Data Request for 2009 are summarized in Table V.B.4. Table V.B.4 lists the peak load reduction forecasting data from utilities reporting their load reductions from demand side programs. Table 4 demonstrates a steady increase in peak load reductions resulting from such programs for all utilities, except Choptank and SMECO, during the 2009-2023 forecast period. These utilities' total peak load reductions totaled 416 MW for 2009 and based on the combined forecast at 3,116 MW for 2023, would result in an estimated annual growth rate of 15.5%.

Table V.B.4: Peak Load Reduction Forecast (MW)

Year	BGE	Choptank	DPL	PE/AP*	Pepco	SMECO	Total
2009	301	10	21	6	67	11	416
2010	583	10	44	17	179	11	844
2011	878	10	137	31	511	11	1578
2012	1335	10	174	43	634	11	2207
2013	1648	11	206	56	676	11	2608
2014	1765	10	225	68	716	11	2795
2015	1892	10	237	78	757	11	2985
2016	1927	11	237	76	757	11	3019
2017	1956	10	237	74	757	11	3045
2018	1982	10	237	72	757	11	3069
2019	2006	10	237	69	757	11	3090
2020	2025	10	237	66	757	11	3106
2021	2039	10	237	60	757	11	3114
2022	2051	10	237	51	757	11	3117
2023	2060	10	237	41	757	11	3116
Change	**1,759**	**0**	**216**	**35**	**690**	**0**	**2,700**
Percentage Change	**584.4%**	**0.0%**	**1028.6%**	**583.3%**	**1029.9%**	**0.0%**	**649.0%**
Annual Growth Rate	**14.7%**	**0.0%**	**18.9%**	**14.7%**	**18.9%**	**0.0%**	**15.5%**

Data Source: Table 4 in the Commission 2009 Ten-Year Data Request includes the Gross Peak Load Forecast (Table 4A) and Net Peak Load Forecast (Table 4B). Data are obtained by subtracting the net of DSM peak load forecast from the gross of DSM peak load forecast as load reduction forecast.
Note: Hagerstown, Easton, Thurmont, and Williamsburg did not report any demand response or load control program.

The major contributors to the peak load reduction are: (1) the current direct load control program (BGE, DPL, Pepco, and SMECO); (2) legacy load reduction program (BGE, SMECO, and Choptank); (3) BGE's Smart Grid Initiative,[33] and (4) energy efficiency & conservation programs (BGE, DPL, Pepco, PE/AP, and SMECO).[34] The peak load forecast for the utilities listed in Table V.B.4 is 14,488 MW for 2009 and 17,793 MW for 2023 without DSM programs. These utilities' peak load forecast is 14,072 MW for 2009 and 14,677 MW for 2023 with DSM programs. Therefore, holding all other factors constant, it is forecast that the DSM programs will reduce the peak demand by over 17 percent (3,116 MW) by 2023.

C. Energy Efficiency and Conservation Programs

On December 31, 2008, the Commission preliminarily approved each of the utilities' EmPower Maryland EE&C portfolios, contingent upon varying Commission-prescribed alterations to their programs, budgets, and projected savings. Although BGE's programs were

33 Pepco and Delmarva did not include demand reductions from their proposed Smart Grid initiatives.
34 The contribution information is obtained through Staff communication with the utilities.

approved in whole, the Commission directed the other utilities to file their revised portfolios, along with information confirming their final estimated costs and budgets through completed RFPs or finalized contracts by March 31, 2009. Comments by the interveners, as well as a response by the utility, have been filed in each proceeding. As with the original series of proceedings, the Commission conducted hearings for each utility's proposal. The remaining four utilities' - AP, DPL, Pepco and SMECO - programs were approved in August 2009.

Two points on the filings warrant comment. *First*, four of the five utilities' plans (Allegheny Power is the exception) meet the Act's goal of a 5 percent peak demand reduction by 2011. By 2015, only BGE, Pepco, and DPL meet the 15 percent reduction in peak demand. None of the utilities meet the 2011 or the 2015 energy consumption target goals.

Second, there is no current baseline study of Maryland customers that allows the utilities or the regulators to assess the reasonableness of the utilities' assumptions regarding participation rates, necessary rebates, and the like. The participants in these proceedings have urged the PSC to initiate such a study so that all parties have a reasonable baseline to utilize when predicting and evaluating program results. The PSC issued an order on December 1 directing the utilities to collaborate on and issue a Request for Proposals ("RFPs") to initiate a State-wide baseline study during 2009, which will help refine these programs going forward and help ensure they are and remain cost-effective. Over the summer of 2009, a Contractor was selected and approved by the Commission, and has since commenced work. The study is expected to be completed by the end of 2010.

Although CY 2008 and 2009 served as a planning and approval year for the EmPower Maryland programs, the task remained to monitor the EmPower target goals. Economic conditions contributed to two out of the five participating utilities succeeding to date in meeting or exceeding 2011 target energy reduction goals and contributed to four utilities meeting their 2011 target demand reduction goal. Allegheny Power remained the farthest behind its compatriots, possibly due to a varying climate and its customers' dependence on electric heating. Obviously, few conclusions can be drawn about the 2015 goals, given that few programs were running this year, but the utilities remain well below the possibility of achieving them even with a sluggish economy and the mild summer weather of 2008 and 2009. It is likely that utilities will be fighting an uphill battle in meeting their 2015 target goals as more typical weather patterns return and the economy rebounds.

Table V.C.1: Five Percent Reduction in Maryland Energy Sales By 2011

Maryland Utility	5 Percent Reduction per Capita Energy Use (MWh)	2008 Actual Reduction per Capita Energy Use (MWh)	Difference Between Actual and Target	Percentage of 2011 Target
AP	16.66	19.49	-2.83	85%
BGE	12.72	12.99	-0.27	98%
Delmarva	12.93	12.60	0.33	103%
Pepco	8.92	9.05	-0.12	99%
SMECO	10.59	10.57	0.02	100%

Table V.C.2: Five Percent Demand Reduction in Maryland Peak Demand By 2011

Maryland Utility	5 Percent Reduction per Capita Energy Use (kW)	2008 Actual Reduction per Capita Energy Use (kW)	Difference Between Actual and Target	Percentage of 2011 Target
AP	2.6	2.7	-0.10	96%
BGE	1.9	2.0	-0.10	95%
Delmarva	3.2	3.4	-0.20	94%
Pepco	3.0	2.8	0.20	107%
SMECO	2.2	2.3	-0.10	96%

Fast-Track Programs

After receiving the Commission's Orders for their EmPower Maryland Programs, some of utilities needed to roll their existing "fast-track" programs[35] under the new EmPower Maryland Lighting & Maintenance programs.[36] The "fast-track" programs were unofficially rolled over in mid-2009 and the results are as follows:

Table V.C.3: Fast Track Programs January - June 2009

Company	Total Measures	Energy Savings (MWh)	Peak Reduction (MW)
BGE	514,406	23,341	3.58
DPL	82,953	4,016	0.28
Pepco	506,300	242,770	1.73
Total	1,103,659	270,127	5.29

The performance of the Lighting Program greatly exceeded the utilities' and the Commission's expectations, selling over 1.1 million CFLs in these programs' last six months of existence. Further, BGE's Appliance Rebate Program resulted in almost 4,000 rebates being processed, roughly on par with 2009 half-year expectations for its current EmPower Maryland version of the Appliance & Lighting Program. Overall, the high participation levels experienced by BGE, DPL, and Pepco are expected to continue as all utilities begin ramping up their EmPower Maryland programs.

EmPower Maryland EE&C Programs

1. BGE

On December 31, 2008, Commission Order No. 82384 approved BGE's Energy Efficiency, Conservation, and Demand Response Programs pursuant to the EmPower Maryland Energy Efficiency Act of 2008, along with program revisions in Commission Order No. 82674 on May 13, 2009. The programs approved were aimed towards residential[37], as well as small

35 The "fast-track" programs served as a predecessor to the EmPower Maryland programs, and were mainly compact fluorescent lighting ("CFL") or appliance (e.g., clothes washers, refrigerators, freezers, room air conditioners) buy-down or rebate programs. The purpose of these programs is to provide residential customers with an opportunity to reduce electricity usage and electricity costs and to enjoy energy cost savings quickly and without significant capital expenditures. Costs were recovered through an efficiency surcharge on residential ratepayers' bills.

36 The utilities will include all lighting savings from January 1, 2009 and onward under the Lighting Program in their quarterly reports, but provide a separate line item for "fast-track" program energy and demand savings for easy comparison.

37 The following residential programs have been approved for BGE: the Lighting and Appliance Program; the Home Performance with Energy Star, which includes an online calculator, Quick Home Energy Check-up, and Home Audit; Energy Star for New Homes; Limited Income Energy Efficiency Program; and Residential HVAC Rebate Program.

and large commercial businesses.[38] Generally, most programs are designed to provide either a buy-down or rebate to consumers to encourage the purchase of energy-efficient products, equipment, or services. The Commission approved these programs because they "are designed to permit every single BGE customer to participate and save money well in excess of the cost of the programs."[39]

For 2009-2011, these EE&C programs are estimated to cost a total of $149,207,339. The Commission approved BGE's 2009 Residential EE&C EmPower Maryland Surcharge at $0.00115 per kWh by Letter Order, dated February 6, 2009. The Company's EmPower Maryland EE&C Programs are projected to achieve 52 percent of its 2011 energy savings goal (2,052,948 MWh) and 232 percent of the 2011 peak reduction goal (513 MW). To date, the programs have resulted in an estimated annualized energy savings of 28,177 MWh and 9.74 MW of peak demand reduction.[40]

2. Pepco

On December 31, 2008, Commission Order No. 82385 approved some of Pepco's Energy Efficiency, Conservation, and Demand Response Programs pursuant to the EmPower Maryland Energy Efficiency Act of 2008. At the time, the Commission also requested that Pepco submit a revised EE&C plan that expanded and/or altered some program designs while also revising the total estimated cost and savings with the finalized RFPs. The revised plan was approved on August 13, 2009 in Commission Order No. 82836. The residential[41] and non-residential[42] programs offered by Pepco are similar in nature to BGE's.

For 2009-2011, the total cost of the programs is expected to be $49.8 million. The Commission anticipates that Pepco will file its EmPower Maryland surcharge requests for its 2009 and 2010 program costs in early 2010. The Company's EE&C Programs are projected to achieve 65 percent of its 2011 energy savings goal (685,378 MWh) and 150 percent of the 2011 peak reduction goal (230 MW). Although the bulk of the programs will continue to roll-out through 2009 and into 2010, Pepco has launched its Lighting & Appliance Program and the Online Audit Tool. To date, its EE&C programs have resulted in an estimated annualized energy savings of 24,770 MWh and 2 MW of peak demand reduction.[43]

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[38] The following non-residential programs have been approved for BGE: the Small Business Lighting Solutions Program; Industrial and Commercial Energy Solutions for Business Program, which includes Prescriptive and Custom Programs; and Retrocommissioning Program.

[39] Commission Order No. 82384, issued December 31, 2008, at 1.

[40] These are preliminary figures based upon quarterly reports and are subject to Evaluation, Measurement & Verification ("EM&V").

[41] The following residential programs have been approved for both Pepco and Delmarva: the Lighting and Appliance Program; the Home Performance with Energy Star Program which includes Quick Home Energy Check-up and the Online Audit Calculator; the no cost appliance replacement program for Low Income customers; and the residential HVAC Program.

[42] The following non-residential programs have been approved for both Pepco and Delmarva: the Prescriptive Program; the Heating, Ventilation, and Air-Conditioning Program; the Custom Incentive Program; and the Building Commissioning and Operations & Maintenance Program.

[43] These are preliminary figures based upon quarterly reports and are subject to Evaluation, Measurement & Verification ("EM&V").

3. Delmarva

On December 31, 2008, Commission Order No. 82386 approved some of Delmarva's Energy Efficiency, Conservation, and Demand Response Programs pursuant to the EmPower Maryland Energy Efficiency Act of 2008. At the time, the Commission also requested that Delmarva submit a revised plan that expanded and altered certain programs, revision of the total cost and estimated savings, as well as a confirmation of the RFPs previously issued for the proposed programs. The revised plan was approved on August 13, 2009 by Commission Order No. 82835. The programs offered by Delmarva are the same as Pepco's residential and non-residential programs.

The total cost for the programs from 2009 through 2011 is estimated to be $19.6 million. The Commission expects DPL to file its EmPower Maryland surcharge for its 2009 and 2010 program costs in early 2010. These programs should result in Delmarva obtaining an estimated 54 percent of its 2011 goal (205,846 MWh) for energy savings and 124 percent of the 2011 demand reduction goal (73 MW). Although the bulk of the programs will continue to roll-out through 2009 and into 2010, DPL has launched its Lighting & Appliance Program and the Online Audit Tool. To date, the programs have resulted in an estimated annualized energy savings of 24,770 MWh and 1.7 MW of peak demand reduction.[44]

4. SMECO

On December 31, 2008, some of the programs for SMECO's Energy Efficiency, Conservation, and Demand Response were approved in Commission Order No. 82387. On August 13, 2009, the Commission approved the revised plan which included new or altered programs, its budget, and projected energy savings in Commission Order No. 82834. The programs that were approved included programs for residential customers[45] and a Customer Incentive program for non-residential customers.

The total cost for the 2009-2011 programs is estimated at $14.3 million. The Commission expects SMECO to file its EmPower Maryland surcharge in early 2010. The programs are expected to yield 88 percent of the 2011 energy reduction goal (94,229 MWh) and 206 percent of the 2011 peak reduction goal (29 MW). Since the August Commission Order, only the On-line Audit Tool and PowerWise programs[46] have been instituted. SMECO plans to launch the majority of its programs by early 2010. Neither energy savings nor peak reduction has been generated because SMECO has yet to begin implementing its programs.

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44 Ibid.

45 The following residential programs have been approved for SMECO: the Lighting and Appliance Program; HVAC and DHW Program; New Construction-Energy Star Home Program; PowerWise Program, which includes an Online Energy Audit and On-site Energy Audit; and Home Performance for Low Income.

46 The residential PowerWise Program is comparative to BGE's Home Performance with Energy Star. The name was not changed due to customer familiarity, as the program has been running since 1996.

5. Allegheny Power

On December 31, 2008, the Commission approved AP's design of the Company's proposed energy efficiency and demand response programs.[47] Subsequently, on August 6, 2009, the Commission approved the budget and savings projections for the previously approved programs in Commission Order No. 82825. The programs that were approved were directed to both residential[48] and non-residential[49] customers, and included the redesign of the Residential Assistance Program, the Home Energy-Efficiency Loan Program, and the Home Performance with ENERGY STAR Program.

The total cost for these programs from 2009 through 2011 is estimated to be approximately $33 million. AP expects to reach 90 percent of the energy savings goal (122,664 MWh) and 72 percent of its demand reduction goal for 2011 (49.4 MW). By Letter Order, dated October 6, 2009, the Commission approved AP's Residential EE&C EmPower Maryland Surcharge at $0.00109, amortizing 2009 and 2010 EmPower Maryland costs over a 15 month period. AP expects to ramp up and roll out some of these programs prior to the beginning of 2010. Therefore, no energy savings or demand reductions figures are available at this time.

D. Advanced Metering Infrastructure / Smart Grid

1. Background

"Smart grid" technology is generally defined as a two-way communication system and associated equipment and software, including equipment installed on an electric customer's premise that uses the electric company's distribution network to provide real-time monitoring, diagnostic, and control information and services that improve the efficiency and reliability of the distribution and use of electricity. Advanced Metering Infrastructure ("AMI") is a component of smart grid and refers to the installation of meters on a customer's premise capable of being addressed by the utility and read by the customer. Many times AMI and smart grid are used interchangeably. The proponents of deploying advanced meters argue the technology enables customers to see and respond to market based pricing, can assist in increasing grid reliability and may act to reduce environmental impacts. Consequently, "Smart grid" technology can ameliorate the need to dispatch generation facilities at peak electric usage periods and reduce congestion costs, while simultaneously assisting to forestall power plant construction. Reliability and power quality benefits can also accrue when AMI is employed to reduce blackout probabilities and forced outage rates while restoring power in shorter time periods.

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[47] Commission Order No. 82383.

[48] The following residential programs have been approved for Allegheny Power: CFL Rewards Program; Energy Star Appliance Program; HVAC Efficiency Program; and Home Performance, which includes an On-line Energy Audit, Quick Home Energy Check-up, and Comprehensive Home Audit.

[49] The following non-residential programs have been approved for Allegheny Power: the Lighting Program; the A/C Program; the Variable Frequency Drive measure of the Motor & Drives Program; and the Custom Program.

On June 8, 2007, the MDPSC established a collaborative process to consider four issues pertaining to AMI and DSM programs: technical standards; extent to which programs are to be offered; program cost recovery; and the appropriate tests to determine cost effectiveness.

On September 28, 2007, the Commission issued Order No. 81637 that established the following minimum technical standards for AMI:

- A minimum of hourly meter reads delivered one time per day;
- Non-discriminatory access for retail electric suppliers and curtailment service providers to meter data and demand response functions that is equivalent to the electric company's own access to those functions;
- AMI shall be implemented for all customers of the electric company;
- Metering and meter data management and AMI/DSM implementation should generally continue to be an electric company function;[50]
- All AMI meters shall have the ability to monitor voltage at each meter and report the data in a manner that allows the utility to react to the information;
- All meters shall have remote programming capability;
- All meters shall be capable of two-way communications;
- Remote disconnect/reconnect for all meters rated at below 200 amps;
- Time-stamp capability for all AMI meters;
- All meters shall have a minimum of 14 days of data storage capability on the meter;
- All meters shall communicate outages and restorations; and
- All meters shall be net metering and bi-directional metering capable.

On February 19, 2009, President Barack Obama signed into law the American Recovery and Reinvestment Act ("ARRA"). The ARRA provides targeted support for the development of a Smart Grid, with $4.5 billion appropriated to the U.S. Department of Energy ("DOE") for spending on grid modernization, demand responsive equipment, energy storage research, development, demonstration and deployment and, most significantly for smart grid businesses, implementation of smart grid programs created under the Energy Security and Independence Act of 2007 ("ESIA").

Four Maryland utilities filed for matching funds under the Smart Grid Investment Grant ("SGIG") program administered by the United States Department of Energy: BGE, Pepco, Delmarva, and SMECO. BGE was awarded $200 million in funds from DOE, $136 million for AMI and $34 million for demand response. The remaining $30 million is for an upgrade to the Customer Information System. The $136 million funding for AMI represents 16.3% of the $835 million of total projected cost for deploying AMI. Pepco was awarded $104 million in funds from DOE, $69 million for AMI and $26 million for demand response. The remaining $9 million is for Distribution Automation and Communication Infrastructure upgrades. The $68.9

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50 Metering and data management options may be considered for larger non-residential customers (this does not exclude any customer from a requirement that their AMI shall at a minimum be fully consistent with all AMI standards). For example, if an industrial or commercial customer (and its retail supplier or CSP) requires more frequent meter reads or downloads, the utility shall work in good faith to accommodate such requirements.

million for AMI represents 38.2% of the $180 million total projected cost of Pepco's AMI proposal.

2. BGE

On July 13, 2009, BGE filed an application for authorization to deploy a Smart Grid initiative and to establish a tracker mechanism for the recovery of costs. Highlights of the applications are as follows:

- Install over 2 million electric meters and gas modules;
- Deployment cost of $434 million in capital costs and $48 million in operations and maintenance ("O&M") expenses;
- Total costs over the life of the program of $641 million in capital costs and $194 million in O&M;
- Total benefits over the life of the program estimated at $2.6 billion;
- The cost effectiveness test yields a value of 2.4;
- Provide an estimated additional 610,000 MWh in energy savings and 500 MW in demand reduction towards BGE's 2015 EmPower Maryland goals;
- A new rate scheduled for all residential customers that include mandatory TOU rates in the summer and a Peak Time Rebate ("PTR") dynamic pricing structure to incent customers to reduce usage during the hours of 2pm to 7pm during called critical events; and
- Proposed cost recovery through a tracker mechanism as a fixed monthly customer charge.

The Commission docketed Case No. 9208[51] by Order No. 82823 issued August 5, 2009. Interveners included Staff, OPC, MEA, and AARP. Hearings for this matter commenced on November 10, 2009 and at the time of this report, the Commission had not issued its final order.

3. Pepco and Delmarva

On March 26, 2009, Pepco and Delmarva filed a request for expedited approval to establish a regulatory asset for the deployment of AMI. The Commission considered this request at the June 10 and June 29 Administrative Meetings and on August 5, 2009 issued Order No. 82824 which denied the Companies' prior requests and docketed Case No. 9207[52] that set a procedural schedule for its consideration of the Companies' proposals.

On September 1, 2009, the Companies filed direct testimony in support of the Companies' AMI proposals that included the following highlights:

- Install over 570,000 electric meters in Pepco's territory and 221,000 electric meters in Delmarva's territory;

51 In the Matter of the Application of Baltimore Gas And Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost.

52 In the Matter of the Application of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure.

- Total capital costs of $127.7 million for Pepco and $51 million for Delmarva;
- Total costs for the life of the program are estimated at $180.2 million for Pepco and $72 million for Delmarva;
- Total benefits for the life of the program are estimated at $313.5 million for Pepco and $120.6 million for Delmarva;
- Cost-effectiveness results are 1.74 for Pepco and 1.68 for Delmarva;
- Provide a combined estimated additional 450,000 MWh in energy savings and 992 MW in demand reductions towards Pepco's and DPL's 2015 EmPower Maryland goals;
- All customer classes will be defaulted into a Critical Peak Rebate structure, with the option to choose to return to the standard offer rates or Critical Peak Price; and
- Pepco and Delmarva propose to establish a regulatory asset with cost recovery of the asset to be determined in the Companies' next base rate cases.

Hearings for this matter commenced on November 19, 2009 and at the time of this report, the Commission had not issued its final order.

4. Allegheny Power

AP has included an AMI pilot proposal as a part of its EmPower Maryland filing with the following highlights:

- Pilot to run in the city of Urbana;
- Pilot will last 15 months;
- 1,140 customers to receive an advanced meter;
- Some customers will receive a smart thermostat to control electric central air conditioning and/or a device for electric hot water heaters; and
- Pilot will test customer's response to real time pricing.

After numerous discussions with Staff, MEA, and OPC primarily concerning the need for another pricing pilot in Maryland, AP withdrew its pilot proposal.

5. SMECO

On October 2, 2009, SMECO filed with the Commission its proposed AMI Pilot program. SMECO has proposed a two-phase pilot to test the operational benefits of AMI deployment such as savings from eliminating meter readings and improved outage restoration. Phase I of the pilot would include the installation of 1,000 meters in one section of the territory and would last 9 months. SMECO would report the results of Phase I to the Commission prior to implementing Phase II, which would be a 10,000 meter deployment across the entire service territory. SMECO proposed the following timeline for its pilot program.

January 2010	Commission Approval of Phase I
June 2010-September 2010	Meters installed and operational
September 2010-February 2011	Data gathering
February/March 2011	Report Results to Commission

August 2011	Commission Approval of Phase II
November 2011-August 2012	Phase II commences

At the time of this report, the Commission has not yet ruled on SMECO's application.

E. Mid-Atlantic Distributed Resources Initiative ("MADRI")

MADRI was established by "classic" PJM State Commissions, DOE, and PJM at a meeting in Baltimore, held on June 14-15, 2004. Its goal is "to develop regional policies and market-enabling activities to support distributed generation and demand response in the Mid-Atlantic region". Facilitation support is provided by the Regulatory Assistance Project funded by DOE. There has been much participation by a large number of stakeholders, including utilities, FERC, service providers, and consumers. During 2009, MADRI had activities in the following areas:

- Assisting FERC in its development of a National Action Plan for Demand Response;
- Smart grid and dynamic pricing issues including interoperability, critical peak pricing, cyber security, technology and function options and standards;
- The Maryland Commission Staff's Distributed Generation Work Group report and recommendations;
- Regional PJM transmission system planning and distributed resources; and
- Updates and discussion of demand side initiatives and developments in the MADRI states.

VI. ENERGY, THE ENVIRONMENT AND RENEWABLES

A. Maryland's Commission on Climate Change

On April 20, 2007, Governor O'Malley signed Executive Order 01.01.2007.07, which established the Maryland Commission on Climate Change ("MCCC"). The MCCC is comprised of sixteen State agency leaders, including the Chairman of the Public Service Commission, and six members of the General Assembly. The MCCC's primary charge was to develop a *Climate Action Plan* to address the drivers of climate change,[53] prepare for its likely impacts in Maryland, and establish goals and timetables for implementation of mitigation and adaptation strategies. Furthermore, the Executive Order requires the MCCC to report on the *Climate Action Plan* to the Governor and General Assembly in November of each year.

Table VI.A.1 displays the greenhouse gas ("GHG") emissions reduction goals established by the MCCC. The goals are based on GHG emissions reductions from a 2006 base year, and are purposely very aggressive.

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[53] Maryland Department of the Environment, The *Climate Action Plan,* Maryland Commission on Climate Change, August 2008. Available: http://www.mdclimatechange.us/

<u>Table VI.A.1: Maryland Commission on Climate Change Goals</u>

Year	Maryland's Goals
2012	10% Reduction from 2006 Levels
2015	15% Reduction from 2006 Levels
2020	Minimum Goal - 25% Reduction From 2006 Levels
2020	Aspiration Goal - 50% Reduction From 2006 Levels
2050	90% Reduction From 2006 Levels

The Maryland Department of Environment is the lead agency of the MCCC. The work of the MCCC is founded on the assumption that excess carbon dioxide and other GHG released by human activity is the leading contributing factor to climate change. The MCCC's three working groups undertake technical work that is focused on identifying and implementing mitigation and adaptation strategies that have the potential to reduce the impact of climate change.

In January 2008, the Commission on Climate Change issued an *Interim Report* which included a variety of recommendations for legislative action, and the General Assembly adopted a number of them during the 2008 legislative session, including:

- The EmPOWER Maryland Energy Efficiency Act of 2008;
- A Strategic Energy Investment Fund and a Strategic Energy Investment Program;
- Amending the Renewable Portfolio Standard to accelerate requirements; and
- The High Performance Buildings Act of 2008.

During the 2009 Legislative Session, the Maryland General Assembly passed the Greenhouse Gas Emissions Reduction Act of 2009 ("GGRA"). The GGRA requires a 25 percent reduction of Statewide GHG emissions by 2020, using a 2006 baseline. The MCCC released the *Update to Governor and General Assembly* report in February 2010.[54] The annual report provides an update on the development of the *Climate Action Plan*, implementation timetables and benchmarks, and preliminary recommendations, including possible draft legislation for consideration by the General Assembly for the upcoming legislative session.

The Commission on Climate Change issued its *Climate Action Plan* in August 2008. Building on the *Interim Report*, the *Climate Action Plan* contains studies and recommendations of the MCCC's three working groups: the Scientific and Technical Working Group; the Adaptation and Response Working Group ("ARWG"); and, the Greenhouse Gas and Carbon Mitigation Working Group ("MWG"). The *Climate Action Plan* details possible effects climate change will have on the State, recommends 19 actions to protect Maryland's property and people from rising sea levels and changing weather patterns, and outlines 42 actions to help the State greatly reduce GHG emissions. The report concludes that Maryland would see significant economic and environmental benefits from taking early, immediate actions to reduce GHG

[54] Maryland Department of the Environment, *Update to Governor and General Assembly*, Maryland Commission on Climate Change, January 2010. Available: http://www.mde.state.md.us/assets/document/Air/ClimateChange/Report_1.pdf

emissions and that the goals proposed by the MCCC are achievable and would help spur innovation in the State.

The *Climate Action Plan* identified 42 mitigation strategies to reduce GHG emissions and 19 adaptation and response strategies to reduce the potential impacts of climate change on Maryland. The MCCC identified lead agencies for each policy option. These policies and lead agencies, which are responsible for development and implementation of the policies, are identified in Table VI.A.2 and Table VI.A.3. The Maryland Public Service Commission is the lead agency for the policy options relating to the Renewable Energy Portfolio Standard and Integrated Resource Planning.

Table VI.A.2: MWG Policy Options

Greenhouse Gas and Carbon Mitigation Working Group (MWG) Policy Options		
Cross-Cutting (CC)	**Number**	**Lead Agency**
GHG Inventory and Forecasting	CC-1	MDE
GHG Report and Registry	CC-2	MDE
Statewide GHG Reduction Goals and Targets	CC-3	MDE
State and Local Government Lead-by-Example	CC-4	MDE
Public Education and Outreach	CC-5	MDE
Review Institutional Capacity	CC-7	MCCC
Participate in Regional, Multi-State and National Efforts	CC-8	MDE
Promote Economic Development Opportunities	CC-9	DBED
"After Peak Oil"	CC-10	MEA
Public Health Risks	CC-11	DHMH
Residential, Commercial, and Industrial Buildings (RCI)	**Number**	**Lead Agency**
Improved Building Codes and Trade Codes	RCI-1	DHCD
Demand-Side Management and Energy Efficiency	RCI-2	MEA
Low-Cost Loans for Energy Efficiency	RCI-3	MEA
Improved Design, Construction, Appliances and Lighting	RCI-4	MDE
More Stringent Appliance/Equipment Efficiency Standards	RCI-7	MEA
Energy Efficiency Resource Standard	RCI-10	MEA
Promotion and Incentives for Energy Efficiency Lighting	RCI-11	MEA
Energy Supply (ES)	**Number**	**Lead Agency**
Promotion of Renewable Energy	ES-1	MEA
Technology-Focuses Initiatives for Electricity Supply	ES-2	MEA
GHG Cap-and-Trade	ES-3	MDE
Clean Distributed Generation	ES-5	MEA
Integrated Resource Planning	ES-6	PSC
Renewable Portfolio Standard	ES-7	PSC
Efficiency Improvements and Repowering Existing Plants	ES-8	MEA
Generation Performance Standards	ES-10	MDE
Agriculture, Forestry and Waste (AFW)	**Number**	**Lead Agency**
Forest Management for Enhanced Carbon Sequestration	AFW-1	DNR
Managing Urban Trees and Forests	AFW-2	DNR
Afforestation, Reforestation and Restoration of Forests and Wetlands	AFW-3	DNR
Protection and Conservation of Agricultural Land, Coastal Wetlands and Forested Lands	AFW-4	MDA
"Buy Local" Program	AFW-5	MDA
Expanded Use of Forest and Farm Feedstocks and By-Products for Energy Production	AFW-6	DNR
In-State Liquid Biodiesel Production	AFW-7b	MEA
Nutrient Trading with Carbon Benefits	AFW-8	MDA
Waste Management and Advanced Recycling	AFW-9	MDE
Transportation and Land Use (TLU)	**Number**	**Lead Agency**
Land Use and Location Efficiency	TLU-2	MDOT
Transit	TLU-3	MDOT
Intercity Travel	TLU-5	MDOT
Pay-As-You-Drive Insurance	TLU-6	MIA
Bike and Pedestrian Infrastructure	TLU-8	MDOT
Incentives, Pricing and Resource Measures	TLU-9	MDOT
Transportation Technologies	TLU-10	MDE/MDOT
Evaluate GHG from Major Projects	TLU-11	MDOT

Table VI.A.3: ARWG Policy Options

Adaptation and Response Working Group (ARWG) Policy Options		
ARWG Cross-Cutting (ARWG)	**Number**	**Lead Agency**
Public Awareness, Outreach, Training and Capacity Building	ARWG-1	DNR
Local Government Planning Guidance	ARWG-2	DNR
Future Adaptation Strategy Development	ARWG-3	UM
Future Built Environment and Infrastructure (FBEI)	**Number**	**Lead Agency**
Integrated Planning	FBEI-1	DNR
Adaptation-Stat	FBEI-2	DNR
Climate Change Insurance Advisory Committee	FBEI-5	MIA
GIS Mapping, Modeling and Monitoring	FBEI-6	DNR
Green Economic Development Initiative	FBEI-8	DBED
Existing Built Environment and Infrastructure (EBEI)	**Number**	**Lead Agency**
Integrated Observation Systems	EBEI-2	DNR
Adaptation of Vulnerable Coastal Infrastructure	EBEI-3	DNR
Building Code Revisions and Infrastructure Design Standards	EBEI-8	DHCD
Disclosure	EBEI-10	DHCD
Resources and Resource-Based Industry (RRI)	**Number**	**Lead Agency**
Natural Resource Protection Areas	RRI-1	DNR
Forest and Wetland Protection	RRI-2	DNR
Shoreline and Buffer Area Management	RRI-3	DNR
Resource-Based Industry Economic Initiative	RRI-4	DNR
Human Health Safety and Welfare (HHSW)	**Number**	**Lead Agency**
Health Impact Assessments	HHSW-1	DHMH
Inter-Agency Coordination	HHSW-2	DHMH
Vector-borne Surveillance and Control	HHSW-9	DHMH

B. The Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative ("RGGI") is the first mandatory cap-and-trade program in the United States for carbon dioxide. Under RGGI, ten northeastern and Mid-Atlantic States have jointly designed a cap-and-trade program that caps carbon dioxide emissions from power plants and then lowers the cap by ten percent by 2018. RGGI, Inc. is a nonprofit corporation formed to provide technical and scientific advisory services to participating states in the development and implementation of the carbon dioxide budget trading programs.

Under RGGI, the participating states have agreed to use an auction of allowances as the means to distribute allowances to electric power plants regulated under coordinated state carbon dioxide cap-and-trade programs. All fossil fuel electric power plants 25 megawatts or greater must obtain allowances and adhere to RGGI guidelines.

The effective date for RGGI is January 1, 2009. From 2009 through 2014 the cap stabilizes emissions at current levels of approximately 188 tons annually until 2015. Beginning in 2015 the cap is reduced by 2.5 percent each year until 2018. The first compliance period is the period from 2009 to 2011. The initial base annual emissions budget for the 2009-2014 periods is as follows:

Table VI.B.1: State CO_2 Allowances (2009 – 2014)

State	Carbon Dioxide Allowances (in Short Tons)
Connecticut	10,695,036
Delaware	7,559,787
Maine	5,948,902
Maryland	**37,505,984**
Massachusetts	26,660,204
New Hampshire	8,620,460
New Jersey	22,892,730
Rhode Island	2,659,239
Vermont	1,225,830
Total	**1,888,078,977**

Source: The Regional Greenhouse Gas Initiative: Memorandum of Understanding. http://www.rggi.org

This phased approach with initially modest emissions reductions is intended to provide market signals and regulatory certainty so that electricity generators begin planning for, and investing in, lower-carbon alternatives throughout the region, but without creating dramatic wholesale electricity price impacts and attendant retail electricity rate impacts. The RGGI memorandum of understanding apportions carbon dioxide allowances among signatory states through a process that was based on historical emissions and negation among the signatory states. Together, the emissions budgets of each signatory state comprise the regional emissions budget or RGGI "cap."

In 2009, RGGI held four successful auctions for carbon dioxide allowances (an allowance is a limited permission to emit one ton of carbon dioxide) on March 18th, June 17th, September 9th and December 2nd; six total auctions for RGGI thus far. In 2008, two auctions were held for carbon dioxide allowances. Table VI.B.2 summarizes all of the RGGI auctions held to date. The auction closing prices for 2009 allowances decreased from $3.51 per allowance at the first auction held in 2009 to $2.05 at the last auction held in December. The 2012 allowances sold in 2009 auctions also decreased from $3.05 per allowance to $1.86 per allowance at the last auction in December. Maryland's Strategic Energy Investment Fund received $34,389,987 from auctions held in 2008 and $61,881,590 from auctions held in 2009 for a cumulative total of $96,271,577. In part, the SEIF supports renewable and energy efficiency programs and provides rate relief. Auctions of carbon dioxide allowances are held quarterly with the next auction scheduled for March 10, 2010.

Table VI.B.2: Annual Emissions Budget (2009 – 2014)

Number	Auction Date	2009 Allowances	2009 Proceeds	Price per Allowance	2012 Allowances	2012 Proceeds	Price per Allowance	Total Auction Proceeds
1	25-Sep-2008	5,331,781	$16,368,568	$3.07				$16,368,568
2	17-Dec-2008	5,331,781	$18,021,420	$3.38				$18,021,420
3	18-Mar-2009	5,331,783	$18,714,558	$3.51	399,884	$1,219,646	$3.05	$19,934,205
4	17-Jun-2009	5,331,782	$17,221,656	$3.23	399,884	$823,761	$2.06	$18,045,417
5	9-Sep-2009	5,331,782	$11,676,603	$2.19	399,884	$747,783	$1.87	$12,424,386
6	2-Dec-2009	5,331,782	$10,930,153	$2.05	294,317	$547,430	$1.86	$11,477,583
Cumulative Total		**31,990,691**	**$92,932,957**		**1,493,969**	**$3,338,620**		**$96,271,577**

Source: The Regional Greenhouse Gas Initiative: Auction Results. http://www.rggi.org/co2-auctions/results

RGGI, Inc. is a non-profit Delaware corporation with offices located in New York City in space collocated with the New York Public Service Commission. The RGGI Board of Directors is composed of two representatives from each member state (20 total), with equal representation from the states environmental and energy regulatory agencies. Agency Heads (two from each state), also serving as board members, constitute a steering committee that provides direction to the Staff Working Group and allows in-process projects to be conditioned for Board Review.

C. The Renewable Energy Portfolio Standard Program

Under the Renewable Energy Portfolio Standard (RPS) Program, electricity suppliers are required to meet a renewable energy portfolio standard. This is an annual requirement placed upon Maryland Load Serving Entities (LSEs), which include electricity suppliers and the utilities that provide Standard Offer Service.[55] LSEs file compliance reports with the Commission verifying that the renewable requirement for each entity is satisfied. Additional information regarding the annual status of the Maryland RPS is available in the annual Renewable Energy Portfolio Standard Reports submitted to the General Assembly.[56]

Each supplier must present, on an annual basis, renewable energy certificates (RECs) equal to the percentage specified by the RPS Statute,[57] or pay compliance fees equal to shortfalls. A REC is equal to one megawatt-hour (MWh) of electricity generated using specified renewable sources. As such, a REC is a tradable commodity equal to one MWh of electricity generated or obtained from a renewable energy generation resource. Generators and suppliers are allowed to trade RECs using a Commission-approved system known as the Generation Attributes Tracking System (GATS). GATS is a system designed and operated by PJM Environmental Information Services, Inc (PJM-EIS) that tracks the ownership and trading of the

[55] Standard Offer Service ("SOS") is electricity supply purchased from an electric company by the company's retail customers that cannot or choose not to transact with a competitive supplier operating in the retail market. *See* PUC Article §§ 7-501(n), 7-510(c).

[56] PSC Reports, Available: http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm

[57] Using the Tier 2 RPS requirement as an example, assume a hypothetical LSE operating in the State had 100,000 MWh in retail electricity sales for 2008. In 2008 the Tier 2 requirement was 2.5 percent. Thus, the LSE would have to verify the purchase of 2,500 Tier 2 RECs in satisfaction of the Tier 2 RPS obligation, or pay compliance fees for deficits. Similar requirements apply to Tier 1 and Tier 1 solar: the additional RPS tiers provided for in Maryland's RPS Statute.

generation attributes.[58] A REC has a three-year life during which it may be transferred, sold or redeemed. Suppliers that do not meet the annual RPS requirement are required to pay compliance fees.

Compliance fees are deposited into the Maryland Strategic Energy Investment Fund (SEIF or Energy Fund) as dedicated funds to provide for loans and grants that can indirectly spur the creation of new renewable energy sources in the State.[59] The Commission is responsible for creating and administering the RPS Program; responsibility for developing renewable energy resources through loans and grants has been vested with the Maryland Energy Administration.

The RPS obligation applies to anyone that has completed an electricity sale at retail to customers in the State of Maryland. Eligible fuel sources for Tier 1 RECs and Tier 2 RECs are listed in Table VI.C.1. In order to verify that each electricity supplier, broker, aggregator, and electric company has met its RPS obligation, the Commission requires that all licensed electricity suppliers and electric companies file a Supplier Annual Report no later than April 1st each year.[60] The April 1st deadline provides time for electricity suppliers to calculate electricity sales for the compliance year that ends on December 31st, based on settlement data. The April 1st deadline also allows suppliers time to purchase any RECs needed to fulfill their respective RPS obligations.

Table VI.C.1. Eligible Tier 1 and Tier 2 Resources

Tier 1 Renewable Technologies	Tier 2 Renewable Technologies
• Solar (set-aside with separate standard) • Wind • Qualifying Biomass • Methane (landfill or wastewater treatment plant) • Geothermal • Ocean Energy (waves, tides, currents, and thermal differences) • Fuel Cells (which produce electricity from biomass or methane under Tier 1) • Hydroelectric Power Plant (less than 30 MW capacity) • Poultry Litter-to-Energy	• Hydroelectric Power (other than pump storage generation) • Waste-to-Energy *Note: Tier 1 RECs may be used to satisfy Tier 2 obligations; however, Tier 2 RECs may not be used to satisfy Tier 1 obligations.*

58 An attribute is "a characteristic of a generator, such as location, vintage, emissions output, fuel, state RPS program eligibility, etc." PJM Environmental Information Services, Generation Attribute Tracking System (GATS) Operating Rules, Revision 5, at 3 (December 8, 2008).

59 Chapters 127 and 128 of the Laws of 2008 repealed the Maryland Renewable Energy Fund and redirected compliance fees paid into that fund into the Maryland Strategic Energy Investment Fund.

60 These reports have been filed under PUC Article § 7-705 and Section 20.61.04.02 of the Code of Maryland Regulations.

Electricity suppliers are required to purchase specified minimum percentages of their electricity resources via RECs from Maryland-certified Tier 1 and Tier 2 renewable resources. As presented in Table VI.C.2, Tier 1 and the Tier 1 solar set-aside requirements gradually increase until they peak in 2022 at 18 percent and 2 percent, respectively, and are subsequently maintained at those levels.[61] Maryland's Tier 2 requirement remains constant at 2.5 percent through 2018, after which it sunsets.

Table VI.C.2: RPS Percentage Requirements

Compliance Year	Tier 1*	Tier 1 Solar	Tier 2
2008	2.00%	0.005%	2.50%
2009	2.00%	0.010%	2.50%
2010	3.00%	0.025%	2.50%
2011	4.96%	0.040%	2.50%
2012	6.44%	0.060%	2.50%
2013	8.10%	0.100%	2.50%
2014	10.15%	0.150%	2.50%
2015	10.25%	0.250%	2.50%
2016	12.35%	0.350%	2.50%
2017	12.55%	0.550%	2.50%
2018	14.90%	0.900%	2.50%
2019	16.20%	1.200%	
2020	16.50%	1.500%	
2021	16.85%	1.850%	
2022	18.00%	2.000%	

* Does not include the solar set-aside (Tier 1 Solar)

Suppliers of electricity not meeting the RPS standard pay an Alternative Compliance Penalty (ACP) for shortfalls, as seen in Table VI.C.3. Table VI.C.3 presents the ACP schedule separated by tiers for each year of the RPS from 2008 to 2023 and beyond. Compliance fees, as previously mentioned, are submitted to the Energy Fund and dedicated to supporting the development of new Tier 1 renewable resources in Maryland.

61 "Tier 1 solar set-aside" refers to the set-aside (or carve-out) of Tier 1 for energy derived from a qualified solar energy facilities. The Tier 1 solar set-aside requirement applies to retail electricity sales in the State by electricity suppliers and is a sub-set of the Tier 1 standard.

Table VI.C.3: RPS Alternative Compliance Fee Schedule

Compliance Year	Tier 1 (non-solar)	Solar Tier 1	Tier 2	IPL* Tier 1
2008	$20	$450	$15	$8
2009	$20	$400	$15	$5
2010	$20	$400	$15	$5
2011	$40	$350	$15	$4
2012	$40	$350	$15	$4
2013	$40	$300	$15	$3
2014	$40	$300	$15	$3
2015	$40	$250	$15	$2.50
2016	$40	$250	$15	$2.50
2017	$40	$200	$15	$2
2018	$40	$200	$15	$2
2019	$40	$150		$2
2020	$40	$150		$2
2021	$40	$100		$2
2022	$40	$100		$2
2023 +	$40	$50		$2

* According to PUC §7-705 b (2) and COMAR 20.61.06 E (5), a supplier sale from Industrial Process Load is required to meet the entire Tier 1 obligation for electricity sales, including solar. However, the ACP for an IPL Tier 1 non-solar shortfall and a Tier 1 solar shortfall is the same. For IPL there is no compliance fee for Tier 2 shortfalls.

Calendar year 2009 compliance filings are due to the Commission by April 1, 2010. Calendar year 2008 marked the third compliance year for the Maryland RPS, and the first year for LSEs to comply with the solar Tier 1 set-aside. The RPS compliance reports submitted to the Commission by LSEs and GATS provide information regarding the RECs retired and the underlying renewable energy facilities (*e.g.*, type and location) utilized by electricity suppliers to comport with Maryland RPS obligations.[62] RPS compliance reports were filed by 72 electricity LSEs, including 11 utilities, 33 suppliers, and 28 brokers. RPS compliance reports are due by April 1st every year. There were approximately 64 million MWh of total retail electricity sales in Maryland for 2008: 59.2 million MWh were subject to RPS compliance, and 5 million MWh were exempt.[63]

62 According to PUC Article 7-709, a REC can be diminished or extinguished before the expiration of three years by: the electricity supplier that received the credit; a nonaffiliated entity of the electricity supplier that purchased or otherwise received the transferred credit; or demonstrated noncompliance by the generating facility with the requirements of PUC Article 7-704 (f). In the PJM region, the regional term of art is "retirement," and describes the process of removing a REC from circulation by the REC owner, *i.e.*, the owner "diminishes or extinguishes the REC." PJM Environmental Information Services, Generation Attribute Tracking System (GATS) Operating Rules, at 52-54 (December 8, 2008).

63 According to PUC Article §7-703(a)(2), exceptions for the RPS requirement may include: industrial process load which exceed 300,000,000 kWh to a single customer in a year; regions where residential customer rates are subject to a freeze or cap (under PUC § 7-505); or electric cooperatives under a purchase agreement that existed prior to October 1, 2004, until the expiration of the agreement.

For the 2008 compliance year, electricity LSEs retired 2,684,815 RECs, which was greater than the obligation for the year by over 19,000 RECs. According to the compliance reports filed with the Commission, the cost of RECs retired totaled $2,039,583 for the 2008 compliance year. Comparable REC price data was not collected in 2006 or 2007.[64] For the three compliance years, Table VI.C.4 displays the breakdown of RECs submitted for each tier (MWh), the number of RECs retired in the year by tier (MWh); as well as the payments for the shortfalls in terms of the ACP amount required ($ per MWh).[65] The estimated total costs of all 2008 RECs retired for compliance was just over $2 million and the remaining RPS obligations accrued an ACP balance of $1,241,365.[66]

Table VI.C.4: RPS Supplier Annual Report Results

Electricity Suppliers	RPS Obligation			RPS Compliance Method			
	Tier 1	Solar	Tier 2	Tier 1 RECs	SRECs	Tier 2 RECs	Compliance Fee
Compliance Year 2006	520,073	N/A	1,300,201	552,874	N/A	1,322,069	$38,209
Compliance Year 2007	553,612	N/A	1,384,029	553,374	N/A	1,382,874	$36,374
Compliance Year 2008	1,183,439	2,934	1,479,305	1,184,174	227	1,500,414	$1,235,965

Notably, in 2008 there was a shortfall of 2,707 MWh in RECs for the initial year of the Solar Tier 1 requirement of 2,934 MWh. This shortfall appears largely attributable to the timing of SOS procurement contracts. For residential and small commercial SOS, three of the four Maryland investor-owned utilities purchase two-year supply contracts via competitive bids conducted twice each year.[67] The statute governing the RPS was amended during the Maryland General Assembly's 2007 session to include a specific Tier 1 solar RPS requirement starting January 1, 2008,[68] which occurred during the effective period of a number of existing two-year SOS procurement contracts.[69] Over 98 percent of the total ACPs for the 2008 compliance year

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64 For the 2008 compliance year, the Commission issued data requests to the electricity suppliers in order to supplement the 2008 Annual Supplier Reports with specific REC price data, including Tier 1, Tier 1 Solar, and Tier 2 price data. The 2009 Annual Supplier Reports, due April 1, 2010, now explicitly request this REC price data.

65 The RPS obligation is the total obligation for electricity sales in MWh, which is equal to the number of RECs required for compliance. The number of retired RECs is the actual number of RECs retired for RPS compliance in each corresponding compliance year. The ACP required is calculated by multiplying the difference between the RPS obligation and the actual retired RECs (*i.e.*, the shortfalls) by the applicable ACP and is denominated in U.S. dollars.

66 LSEs can meet RPS obligations through the retirement of RECs or by paying ACPs. LSEs are required to report the total cost of purchasing RECs for compliance.

67 The Potomac Edison Company d/b/a Allegheny Power has been in a transition mode purchasing 5-month to 29-month contracts for its residential and small commercial SOS via competitive bids conducted up to four times a year.

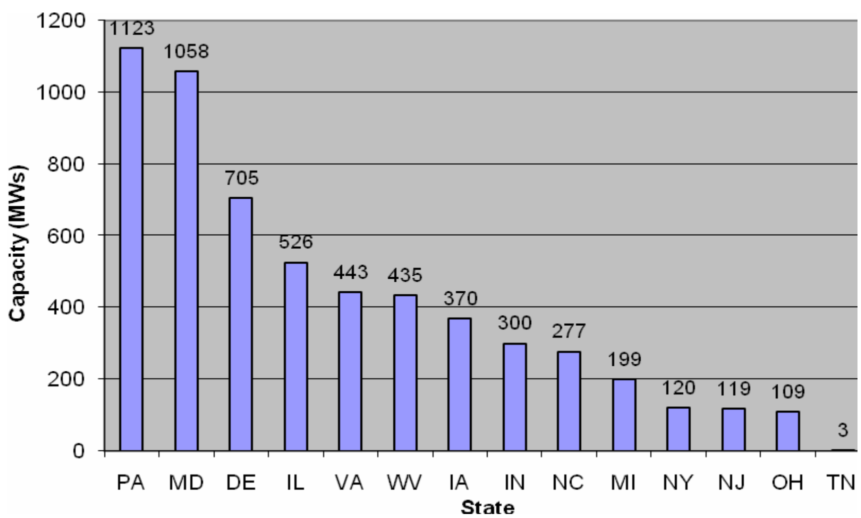
68 Chapters 119 and 120, Acts 2007, codified at Md. Code Ann., PUC, §7-703.

69 Normally renewable electricity (*i.e.*, the RECs) is provided to the utilities as a product component within the wholesale power purchase agreements. However, an SOS service year runs for a 24-month contract term and straddles two RPS compliance years (in this case calendar years 2008 and 2009). In the event the RPS requirement is increased, the contracts supporting SOS require the utilities and suppliers to meet via a stakeholder process to consider terms under which the wholesale suppliers could supply the incremental RPS requirement, but ultimately leave it up to the Commission to determine how this requirement will be met. Stakeholders proposed to have the utilities pay the statutory penalty for noncompliance (*i.e.*, the

are from Solar Tier 1 shortfalls,[70] and the degree to which solar technologies are available to provide renewable output plays a role in the Tier 1 Solar compliance option selected.[71]

Chart VI.C.1 presents the geographical location and the total generating capacity (5,789 MW) for all Maryland RPS-certified facilities regardless of Tier. RPS requirements also exist in the surrounding states, which generally support out-of-state and regional market participation. Seventy-five percent of the renewable facilities that are eligible to participate and potentially provide renewable energy in Maryland reside in the Mid-Atlantic states: Pennsylvania, 19 percent of the potential capacity; Maryland, 18 percent; Delaware, 12 percent; Illinois, 9 percent; Virginia, 8 percent; and West Virginia, 8 percent. The locations of the remaining eligible resources span eight states and in total contribute to 26 percent of the State's eligible capacity.

Chart VI.C.1: MD RPS Certified Rated Capacity by State



With respect to actual electricity and the associated RECs generated from power plant capacity, Pennsylvania supplied the largest number of RECs purchased by Maryland retail electricity suppliers. The majority of the Pennsylvania RECs were from Tier 2 facilities. Virginia was the second most plentiful source of RECs procured by Maryland electric suppliers; additionally, Virginia was the largest source of Tier 1 RECs retired for 2008 compliance purposes. New York, which supplied a relatively equal amount of Tier 1 and Tier 2 RECs, was ranked third in terms of state location for retired RECs. Notably, once statutory changes take

alternative compliance payment or ACP) with the RPS Tier 1 solar requirement for the period from June 1, 2008 through December 31, 2008. The Commission approved the stakeholder proposal. For the period covering January 1, 2009 through May 31, 2009, the stakeholders proposed to develop and conduct a competitive bid to purchase the needed SRECs.

70 Of the remaining portion of ACPs (non-solar) paid, 94 percent was provided by one LSE.

71 As noted above, LSEs can meet RPS obligations by either purchasing available RECs or paying the ACP. For SOS procurement auctions that had occurred before the solar requirement was enacted, it was too late to buy solar RECs for those SOS contracts. Therefore, only the default ACP option was available. However, currently, parties are working to implement a supplemental procurement method for solar RECS for SOS contracts still operative that were procured before the enactment of the current solar REC requirement.

effect in 2011, facilities in New York will only qualify to participate in the Maryland RPS if the electricity is delivered into the PJM region.

D. Solar Power Requirements in Maryland

In 2008, the Commission laid the foundation for an active solar market in Maryland. Regulations were enacted which established a small generator interconnection standard with an expedited process for interconnection of solar facilities. Regulations were adopted establishing the mechanism for creating renewable energy credits, tracking sites, and an on-line solar renewable energy credit application form was introduced to the Commission's website. In 2009, the Commission approved modifications to the solar regulations to reduce the filing requirements on small solar.

The RPS standard requires an electric company to purchase SRECs for 0.01 percent of the State's electricity in 2009. This amount increases incrementally each year until reaching the required 2 percent by 2022. If an electricity supplier fails to offset the applicable percentage of retail electricity sales with electricity derived from solar resources or from SRECs, then the electricity supplier is responsible for making an alternative compliance payment as set forth in PUC Article § 7-705(b). Table VI.C.2 found in Section VI.C summarizes percentage requirements of the Maryland RPS through 2022.

The Maryland Solar RPS grants customers rights to the SRECs each system earns, and requires contract terms to be a minimum of 15 years when the renewable energy credits are purchased by an electricity supplier directly from the solar electricity generator. For facilities that are greater than 10 kW in rated capacity, the stipulation associated with an electricity supplier purchasing SRECs directly from a renewable on-site generator to meet the solar component of the Maryland RPS is that the contract terms for the SRECs must be for no less than 15 years.[72]

An electricity company that purchases SRECs directly from a solar renewable on-site facility that is less than 10 kW in rated capacity must do so through a contract that provides for an up-front lump sum payment for at least 15-years worth of SRECs at a price that is determined by the Commission. The up-front purchase of SRECs is intended to aid in financing the construction of this type of solar installation. The current proposed level of payment for the SRECs is the net present value of the 15-years' worth of RECs using 80 percent of the compliance fee schedule, with a discount rate that is equal to the Federal Secondary Credit Interest Rate.[73]

Unlike most Tier 1 and Tier 2 RECs that may originate from Commission-certified renewable energy facilities that are located in PJM and states adjacent to PJM, the intent of the Maryland solar RPS is for Tier 1 SRECs to originate from solar renewable energy facilities that are interconnected with the electricity distribution grid serving Maryland.

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72 PUC Article § 7-709.

73 See COMAR 20.61.

PUC Article Title 7, Subtitle 7 calls for electricity generated from a Tier 1 solar renewable source to be connected with the electric distribution grid that will be serving Maryland as of January 1, 2012 in order for the generation to be eligible to create Maryland SRECs. Prior to January 1, 2012, Tier 1 solar renewable energy facilities located in PJM are eligible to provide SRECs eligible for the Maryland RPS only to the extent that offers for SRECs derived from Tier 1 solar renewable energy facilities interconnected with the grid are not made to electricity suppliers sufficient to satisfy compliance with the Maryland RPS. All Maryland-based Tier 1 solar renewable energy facilities must be certified by the Commission as a Maryland renewable energy facility, prior to the facility being eligible to create Maryland-eligible SRECs.

E. Distribution Transformer Regulations

Public Utilities Companies Article § 7-212 established that for the purchase of liquid immersed distribution transformers, electric companies would be required to use a life cycle cost methodology contained in Section 2 of Standard TP-1-2002 published by the National Electrical Manufacturers Association. The statute also directed the Commission to adopt regulations governing the purchase of liquid immersed transformers.

The purpose of the requirement is to have electric companies take advantage of higher efficiency products that reduce the electricity losses associated with earlier vintages of liquid immersed transformers.

The Commission established Rule Making 33 to consider regulations in support of Public Utilities Companies Article § 7-212. These regulations are now in effect and may be found at COMAR 20.50.02.06.

VII. ELECTRIC DISTRIBUTION RELIABILITY IN MARYLAND

The Commission supervises and regulates public service companies to promote the adequate delivery of utility services in the State. Adequate, reliable delivery of electricity depends on a well-planned, maintained, and operated distribution system. The Commission requires electric distribution companies to invest in appropriate measures to ensure that reliability of the distribution system in the State is maintained.

COMAR requires that the largest electric distribution utilities file annual reports showing system reliability, based on nationally-recognized reliability indices. COMAR also requires that all electric distribution utilities develop written Operation and Maintenance (“O&M”) procedures and maintain records sufficient to demonstrate compliance with their O&M procedures. Commission Engineering Staff reviews utility records related to O&M procedures to ensure electric utility compliance, monitors distribution system planning, and maintains involvement in a number of other issues related to distribution system reliability.

A. Electric Distribution Reliability Assurance

A perfectly reliable electric distribution system cannot be assured, despite the best planning, operation, and maintenance efforts. As with any other man-made system, mechanical and electrical elements of the distribution system can fail, and such failure can be hastened by severe weather and other outside influences such as trees, animals, and vehicles. However, electric distribution system reliability assurance is a goal that is pursued by monitoring reliability and taking, generally, small steps that lead to maintaining or improving it.

Electric utilities serving 40,000 or more Maryland customers are required to file an Annual Reliability Report with the Commission. The reports contain measurements of reliability for the preceding calendar year of each utility distribution system in terms of both the frequency of outage occurrence and outage duration for the average customer served by the utility. Each investor-owned utility also reports the reliability measurements for a group of the least reliable electric feeders in its systems for the year, along with the remedial actions it has taken to improve the reliability of those feeders. The same feeders are not permitted to appear on a utility's least reliable list in any two successive years under a COMAR provision designed to gradually increase over time the reliability of all feeders in the least performing range. The large electric cooperatives report the operating district with the least reliability for the year, along with the remedial actions taken to improve reliability within those districts.

Electric distribution utilities are generally increasing the automation of distribution feeders, with the potential to reduce both frequency and duration of sustained electric service interruptions. For example, some feeders are connected with other feeders by switches that are normally off (open), but can be closed so that one of the feeders may temporarily supply part or all of the other if it experiences an outage. Currently, many of these switches are manually operated and so it takes time and a utility crew to restore power. If the operation of such a switch is automated, either with local electronic intelligence or through remote operation from the distribution system control or operations center, service outage time to customers can be reduced.

Although electric service interruptions cannot be totally avoided, other utility efforts are focused on limiting the number of customers exposed to any given outage that does occur. Increasingly, fuses, switches, and automatically resetting circuit breakers (reclosers) are being added to distribution system feeder circuits to sectionalize them into smaller protective zones. In this way outages can be isolated to smaller areas, affecting fewer customers.

While some utility activity is designed to increase reliability, inspection and maintenance of existing distribution system equipment must be performed periodically just to maintain a baseline level of reliability. All electric companies serving Maryland have developed written O&M procedures, pursuant to COMAR 20.50.02.04. The O&M procedures must list the specific inspection and maintenance tasks to be performed and the frequency with which the tasks are to be performed. The six largest electric utilities operating in Maryland are required to file the written O&M procedures with the Commission and file annual updates if and when changes in procedures are made. While the procedures vary somewhat from utility to utility, there are many common practices, since the procedures are based on utility experience and accepted good practice within the industry.

In substations, periodic attention is typically given to power transformers, various electrical relays and circuit breakers used primarily for equipment protection, devices charged with controlling voltage such as capacitors and regulators, and banks of batteries that provide backup power for the substation.

For distribution feeder lines, inspection and maintenance attention is typically focused on the electrical conductors in general, capacitors and other voltage regulators, re-closers, electronic monitoring/control devices, vegetation management, and support poles for overhead equipment. Most utilities have ongoing, proactive programs for replacement of aged underground electrical conductors, in addition to such activity in reaction to service interruptions. Some utilities use injections of chemical formulas into existing under ground cable to increase its life expectancy.

Most electric utilities use infrared imaging technology in performing periodic inspections to identify substation equipment that is operating at a temperature higher than the normal range for proper operation. Some utilities include distribution feeder equipment in the inspections. The value in this procedure is that abnormally hot spots in electric conductors or equipment can often be detected and corrected long before they fail due to overheating. The electric distribution system is a large-scale array of electric power circuits and, increasingly, electronic sensing and control circuits. Excessive heat, whether generated internally or by a hot day, is one of the greatest enemies of electric and electronic circuits.

Each utility is required by COMAR to keep sufficient records to give evidence of compliance with its O&M procedures. The Commission's Engineering Division conducts yearly inspection visits to the electric utilities to examine these records, in a continuing effort to assure distribution system reliability. For occasions when a utility fails to show compliance with its O&M procedures, the Engineering Division issues a letter of non-compliance, with expectations that the utility will take remedial actions, usually within 30 days.

For several years, the electric utilities have realized that a collaborative effort among members of the electric utility community can be very useful for assuring reliability when severe weather hits hard. As members of Mutual Assistance Groups, the utilities share restoration crew manpower and other resources when outages increase beyond levels thought to be manageable using the utility's normal resources. Such assistance serves to directly reduce outage duration, one common measure of reliability. In addition to crew sharing, the groups hold conference calls for storm preparation, storm damage assessment, and to discuss overall restoration resource availability.

The four large investor-owned electric utilities operating in Maryland are members of the Mid-Atlantic Mutual Assistance group and the Southeastern Electrical Exchange. Another similar group, Maryland Utilities, includes municipal and cooperative electric utilities. These groups and others will continue to be important alliances in the years to come, as effective distribution outage management and storm restoration requires not only a community-wide effort but sometimes also a regional or national effort.

B. Distribution Reliability Issues

Over time, one of the most persistent reliability issues has been the large amount of electric system damage and numbers of electric service outages that large trees cause when these trees or their branches fall on overhead electric distribution lines or facilities.

Trees receive much public attention during and immediately following hurricanes or other storms, but large trees cause a significant number of electric service interruptions throughout any given year. While electric utilities are usually allowed to control trees within clearly established rights-of-way, such control is not assured. Further, since electric utilities are not permitted to remove all trees near rights-of-way that are capable of falling on overhead lines, electric service reliability as it relates to large trees has never been assured.

By statute, electric utilities are charged with furnishing "equipment, services, and facilities that are safe, adequate, just, reasonable, economical, and efficient, considering the conservation of natural resources and the quality of the environment."[74] Thus, the Commission's enabling legislation clearly establishes the primary responsibilities of electric utilities, and clearly indicates that the utilities must *consider* conservation of natural resources and the quality of the environment in pursuing their primary responsibilities.

Trees are a natural resource, and they contribute positively to the quality of our environment. In consideration for tree conservation and environmental quality when electric distribution rights-of-way for power lines are established, it might be expected that utilities would only remove enough trees to ensure that primary responsibilities are met. However, large trees capable of falling on overhead lines have typically been allowed to exist in close proximity to overhead power lines. Electric utilities often encounter resistance even when simply trimming trees or removing dead or diseased trees near lines. As a practical result, the *primary* responsibilities of electric distribution utilities can become compromise and vegetation management is a continual problem of serious dimensions.

Electric distribution utilities spend millions of dollars each year on tree trimming and vegetation management. While all ratepayers share in that cost, it becomes questionable as to whether or not that cost-sharing arrangement is equitable and *just* to the majority of electric customers who do not own trees capable of causing damage to overhead power lines.

Just as it has been recognized that disaster preparedness and large-scale restoration following a major weather event is a community-wide effort, with utilities playing an expanded role, a community-wide effort must be undertaken if electric system damage and outages due to privately owned trees, are to be reduced.

The prevention of utility damage and service outages caused by privately and publicly owned trees is simply another element of disaster preparedness. Trees take years to grow to the size capable of damaging overhead electric power distribution lines and facilities. The key to preparedness and prevention is to use the advantage of time, to begin action now to remove

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74 See Maryland Public Utility Companies Article, PUC §5-303. Standards of service.

currently existing saplings of large tree species and to disallow planting of large tree species near overhead electric distribution facilities.

BGE and Electric Service Reliability in Bowie

Background

The City of Bowie and the nearby surrounding area is supplied with electric service by twenty-one BGE distribution feeders. Like many other distribution feeder lines across Maryland, each feeder serves 1,000 customers, on average. Like any other grouping of feeders serving a particular area in the State, some of the Bowie feeders have been among the least reliable during some of the years since 2000, when Annual Reliability Report data for least reliable feeders became available.

During the year following each appearance of a Bowie feeder on the utility's least reliable list, BGE has complied with COMAR provisions and taken remedial action with the intent to improve the reliability of the feeders. As is typical for most electric distribution utilities, such action has usually included additional inspections, feeder sectionalizing and protective fusing, hot-spot tree trimming, and underground cable replacement. Less in common with other utilities, BGE has also been adding distribution system automation equipment to its feeders for several years, with the potential for improving service reliability.

Most of the twenty-one Bowie feeders have never appeared on BGE's least reliable list for any year from 2000 to 2008. Nine of the feeders made the list during that period, with one of those feeders appearing three times. That feeder was not determined to be among the least reliable in any two successive years, in accordance with a COMAR provision.

Some of the other Bowie feeders, while not among the least reliable in the last nine years, experienced below-average reliability relative to all BGE feeders, particularly during recent years. BGE has stated that in 2006 and 2007, customers on the twenty-one Bowie feeders experienced, on average, twice the number of service interruptions as compared to the BGE system average. Further, of the total of eleven appearances by Bowie feeders on the least reliable list between 2000 and 2008, eight of the appearances occurred between 2004 and 2007.

The City of Bowie and the surrounding area have been established for some time and are served in large part by overhead electric lines. There are many large trees near the power lines, and many service outages in the area have been caused by large, mature trees very close to the overhead power lines. In 2006, three Bowie distribution feeders appeared on the least reliable list, with trees causing from 51% to 69% of the service outages on those feeders that year. Severe weather compounds the reliability problem as related to trees and overhead lines. BGE reported that during an ice storm in February 2007, Prince George's County experienced a half-inch of ice accumulation, the most among surrounding counties. Trees and tree branches often do not hold up well under the weight of accumulated ice. Following a post-storm inspection of 58 BGE feeders that had locked out due to the storm in 2007, BGE identified 108 feeder problems that needed correction and reported that all but two had been tree-related.

Further compounding the electric service reliability problem as related to trees, much of the Bowie area was developed using back-lot overhead power line construction. In back-lot construction, utility poles and lines are strung across back yards or along property lines that separate the back yards of adjacent residential properties. Property owners dealt with back-lot overhead construction by planting trees to hide poles, power lines, transformers and neighbors, all at the same time. Use of back-lot construction in Bowie contributed to an aesthetic streetscape, with power lines in the back yard out of view. Back-lot overhead power line construction has been a severe detriment to electric service reliability, both in terms of the frequency and the duration of service interruptions.

The BGE Electric Service Reliability Improvement Initiative in Bowie

During the 2004 to 2007 period, numbers of organized Bowie electric customers began complaining about the lack of electric service reliability in the area.

In early 2008, BGE developed the Bowie Electric Reliability Action Plan (BERAP), in cooperation with the Bowie Citizens Task Force. The three-year plan was designed to improve electric service reliability in the Bowie area. In addition to extensive and enhanced tree trimming, the plan involves construction work such as relocation of poles and power lines, including relocation of some overhead lines to underground, installation of stronger poles and tree wire, and the installation or rearrangement of distribution automation equipment.

Collaboration and cooperation are nourished by good communications. Prior to beginning BERAP activity, BGE published a pamphlet that outlined the types of feeder improvements and upgrades to be made, and explained the aggressive vegetation management activity to be included in the plan. The pamphlet was distributed to electric customers in Bowie, and it noted that BGE would keep Bowie residents informed of proposed work through mail, community meetings and individual meetings. During BERAP implementation, and prior to beginning work in each neighborhood, BGE invited the residents to an Open House that provided details of the planned work and an opportunity for residents to ask questions of BGE personnel who would be responsible for performing the work. The utility has maintained communication with customers in Bowie through customer service representatives, personal contact throughout the community and by way of a published newsletter. Customers have received information related to the Right-Tree-Right-Place concept, to encourage the planting of trees of smaller species near overhead power lines. In addition, BGE has provided Commission Staff with site visits to observe BERAP progress, periodic progress updates via email, and a presentation in September 2008 concerning plan progress.

In trimming tree branches for reliable electric service, BGE and other utilities typically try to provide from 6 to 10 feet of clearance between any wire and the closest branches. For main feeder lines, typically with pole cross arms and 3 conducting wires, this desired 6 to 10-foot trimming clearance zone extends from both ends of the cross arm. The clearance zone includes the area lower than the cross arm as well as the area higher than the cross arm, so that branches overhanging the zone are removed, when possible. For single phase tap lines, where a single energized wire is typically strung from pole top to pole top, the utility's standard tree trimming practice calls for trimming of branches within a 6-foot radius of the line axis and includes trimming of any overhanging branches.

Since trees are so prevalent in Bowie and in its electric service reliability history was so troubled, BGE took a more aggressive approach to tree trimming with BERAP. When possible, with cooperation from owners, younger trees less than 8 inches in diameter and pines that are within about 20-25 feet of the pole line were removed. When possible, with cooperation from owners, all hazard trees within 40 feet of the pole line were removed. A hazard tree is generally defined as a tall tree in bad condition that would damage overhead lines and cause service outages if it fell. The enhanced trimming and vegetation management plan includes single phase tap lines serving residences, in addition to the main, two or three phase feeder lines because many tree-related service outages occur on the single phase tap lines.

BERAP calls for tree trimming activity, including some tree removal, on all 21 Bowie feeders and construction work on 12 of the feeders. In September 2008, BGE reported that tree trimming activity was complete on 6 of the feeders and was ongoing on 5 other feeders. At that time, preliminary engineering for feeder construction was complete for all 12 feeders and some construction work had started. At years' end 2008, BGE reported that BERAP was 42 percent complete, with trimming activity complete on 11 feeders and construction work finished or very nearly finished on 3 of the feeders. At various stages of completion, tree trimming and/or construction activity was occurring on 4 other feeders at the close of 2008. The utility reported that during 2008, about 3,800 customers had been contacted and notified concerning tree trimming activity in the area, and that BGE had interacted with more than 800 customers in conjunction with feeder construction work.

As of the end of October 2009, BGE reported that the BERAP project was 92 percent complete. Tree trimming and vegetation management had been completed on 17 of the 21 Bowie feeders included in the BERAP project. Trimming work was in progress on 2 feeders, with activity scheduled to begin on the remaining 2 feeders in November 2009. Underground and overhead feeder construction work had been completed on 10 of 12 feeders, with work in progress on the remaining feeders. BGE reported that, in the BERAP project to date, it had contacted more than 6,000 customers with regard to tree trimming activity and had interacted with more than 2,000 customers as related to its feeder construction efforts.

BGE has promoted the Right-Tree-Right-Place concept that has assisted with appropriate tree plantings in the Bowie area. Through this effort, the utility has invested in the future of electric service reliability in the area.

C. Managing Distribution Outages

A very important tool developed in recent years for managing electric distribution system outages is the computerized Outage Management System ("OMS"). When an outage occurs, a fully developed OMS accepts information inputs from several sources, including customers and systems internal to the utility, and uses that information to help develop output information as to the location and type of equipment that needs attention in order to end the outage. This output information can then be used to generate work orders for repairs or dispatch repair crews by way of a Mobile Dispatch System ("MDS") using two-way radio communication. After repairs are made or other actions taken to end the outage, related outage information is entered as additional input to the OMS. The OMS then knows what customers were affected by the outage, usually what caused the outage, and when it started and ended.

Typical information inputs to the OMS:

- Customer Information System ("CIS"): When a customer calls in an outage, the customer interacts with elements within the utility that have access to the CIS such as a Customer Service Representative, an automated Interactive Voice Response ("IVR") unit or a High Volume Call Service ("HVCS"). The CIS contains the customer's address, can identify the distribution system transformer that serves the customer, and passes this information on to the OMS. The OMS then knows, with assistance from the next two listed inputs, the location of the customer, both in terms of electrical position in the system diagram and geographic position.

  The traditional CIS function is being transformed as many utilities begin to implement elements of Advanced Metering Infrastructure. Advanced electric service meters, featuring two-way communications between customer and utility, provide an information channel that both parties can use to make important decisions related to the efficient supply and use of electricity. AMI also promises faster detection of and more accurate utility response to electric service outages, and promises to largely replace the role of outage detection provided by customer calls within the traditional CIS.

- Energy Management System ("EMS"): The EMS includes an electronic diagram of the electric system showing how elements are connected electrically. The EMS also uses remote monitoring devices such as those of the SCADA system, so that information related to the operational condition of important, major pieces of electric system equipment can be passed on to the OMS.

- Geographic Information System ("GIS"): The GIS includes a map of key landmarks such as streets, and it shows the location of important elements of the electric system relative to those landmarks. This relationship is clearly important in the effort to get repair crews to the heart of the matter. In addition to providing information to the OMS, both the EMS electric system diagram and the GIS map can be displayed on computer monitors and are used by dispatchers to direct the efforts of repair crews.

- Mobile Dispatch System ("MDS") and Work Management System ("WMS"): After an outage is cleared, a work order is closed out within the WMS, or in some cases the repair crew can directly close the outage with, and enter related information directly into, the OMS using the MDS. The WMS or MDS information usually includes the time of restoration and the cause of the outage. After this information input is made, the OMS then contains an archive of important information about the entire history of the outage.

Typical Information outputs from the OMS:

- Information about the type of equipment involved in the outage and its location is passed to the WMS or MDS so that crews can be effectively dispatched to clear the outage.

- Prior to the clearing of an outage, an Estimated Time of Restoration (ETR) and other information can be fed back to the CIS, so customers calling in who are affected by a particular ongoing outage may be kept informed.

- Information concerning outages can be extracted from the OMS in near real-time to feed Internet web-sites containing outage reports or outage maps.

- The OMS can be queried for outage information to be used to generate reports concerned with reliability statistics for the entire distribution system or any part thereof.

The four large investor-owned electric utilities operating in Maryland and the Choptank and SMECO electric cooperatives have implemented OMS, each with functionality developed generally to the extent described above.

Improvements and efforts to increase the functionality of the OMS elements are ongoing. As with most computer and software-based systems, the OMS evolves with each new software upgrade, and as utilities learn how to best utilize the systems. The following are summaries of recent or planned activity by the largest electric utilities operating in Maryland to increase the utility of OMS.

1. <u>Energy Management System</u>

a. Allegheny

Allegheny is currently upgrading its EMS, implementing both the latest software version release and new hardware from its EMS vendor. The upgraded EMS is currently scheduled to go on line during the first half of 2011.

b. BGE

BGE plans remain in place to replace its current EMS communications computer processor to accommodate future SCADA expansion, to provide increased ability to monitor and control the distribution system. In addition to replacing existing communication hardware that may not be well supported by the manufacturer in the future, the new equipment will reportedly allow unlimited SCADA expansion. This project is currently projected for completion in 2011. BGE plans an upgrade of its Electric Energy Control System to use more current technology, scheduled to begin in 2010 and be operational in 2012.

c. Choptank

Choptank currently uses power line carrier signals and cellular telephone technology to communicate with its energy management devices in the field from its Denton headquarters, but indicates that communication coverage is incomplete throughout its distribution system. The

Cooperative is continuing a gradual migration toward implementing a fiber optic network communications scheme for energy management and other communications functions, to include some remote control of some system assets.

d. DPL and Pepco

Pepco and DPL plan to implement a common EMS platform, with expected productivity and operations improvements due to use of a common system. The new system would interface with the separate electrical connectivity models of the two utilities. Current plans call for implementation by April 2010 for Pepco, and by years' end 2010 for DPL.

e. SMECO

In order to integrate the planned AMI structure with its OMS, SMECO needs expanded SCADA capability and functionality within its EMS. SMECO expects to begin to gather requirements for SCADA expansion and develop a Request for Proposals in 2010, and to implement the expansion in 2011.

2. Geographic Information System

a. Allegheny

Allegheny expects to upgrade or enhance its GIS in either 2010 or 2011 to support energy efficiency and conservation programs enabled by the use of advanced customer service meters.

b. BGE

BGE refers to its existing system as the Geospatial Information System, and currently has plans to enhance the system over the next several years. The utility hopes to expand the use and functionality of the system to improve process standardization, increase integrity and currency of data about its system, reduce the potential for public safety incidents, and improve operational efficiency. BGE expects this enhancement initiative to continue for several years, with a goal of achieving better integration of the GIS with the OMS, CIS, work management system, mobile operations and its electric distribution system design operations.

c. Choptank

Choptank upgraded its GIS in June 2009 to the ArcFM product made by Telvent Miner & Miner, and is currently making data additions to the system.

d. DPL and Pepco

Pepco currently uses a GIS platform from ESRI, a GIS and mapping company originally founded as Environmental Systems Research Institute, Inc. Pepco completed an upgrade of its GIS to ESRI version 9.2 last year. DPL had been using another system but also converted to ESRI 9.2 in November 2008. Pepco uses Graphical Work Design ("GWD") software that allows electric system designers to integrate work with location information from the GIS. DPL plans to begin using the same GWD software as Pepco by the second quarter of 2010.

e. SMECO

SMECO notes that its GIS is currently the sole source of geographic spatial data used by its various computer applications. SMECO is one of the few large electric utilities that have not historically used pole numbers to identify equipment locations in the field. Currently using version 9.2 of the ArcGIS/ArcFM system, the cooperative intends to upgrade to version 9.3 in 2010.

3. Mobile Dispatch System

a. Allegheny

Allegheny does not utilize an MDS and currently does not have plans to implement a system within the next few years. However, the utility is currently implementing a related technology, Automated Vehicle Locating Devices ("AVL") in each of the vehicles used by linemen, meter-reading personnel, supply chain personnel and meter technicians. Use of the devices will allow the utility's crew dispatchers and management to track the location of company personnel during the work day. The utility expects to realize efficiency gains within the operations and management of each of those operational areas. AP expects full implementation of AVL for its Maryland operations by the time this report is issued.

b. BGE

In September 2009, the utility began efforts to consolidate the two separate MDS platforms it had been using. Efforts in future years will involve extending the system for use by all field crews and to integrate it with other business systems, such as the CIS, WMS, and asset management systems.

c. Choptank

Choptank does not utilize an MDS and currently does not plan to implement such a system.

d. DPL and Pepco

DPL currently uses an MDS software platform called Ventyx Advantex/Service Suite for mobile applications. Late last year, Pepco implemented the same platform for use by its field service personnel responsible for clearing service outages and addressing other problems with the distribution system. Pepco expanded use of the platform to customer Meter Service work personnel in August 2009. Pepco plans to implement the platform for use by Customer Care personnel during the second quarter of 2010.

e. SMECO

SMECO launched the first phase of its MDS in July 2007, with initial training of service crews and supervisors designated as the utility's first response task force. For Meter Operations and Credit & Collections service orders, the new MDS was implemented in the first quarter of 2008. SMECO indicated that this implementation has enhanced the functionality of service technicians, metering crews and customer service field technicians, since the MDS directly interfaces with the Cooperative's customer care application. The third phase of MDS implementation, to use the MDS to assist with Construction Operations work orders, was completed in early 2009. The cooperative is currently implementing the MDS for use by underground-cable-locating and storm-assessment personnel. Planned enhancements for the MDS in 2010 include mileage and timesheet recording capabilities for mobile field personnel.

4. <u>Work Management System</u>

a. Allegheny

Allegheny currently plans to upgrade or enhance its WMS in either 2010 or 2011. The utility expects that the improvements will support energy and efficiency programs enabled by the use of advanced customer service meters.

b. BGE

In 2008 and 2009, BGE implemented the first two phases of a new, computerized WMS that consolidates asset tracking and data for its electric distribution system, as well as for its gas and electric transmission networks. Future phases of the program are planned to include standardized, company-wide processes for construction, maintenance and service meter work. BGE expects the overall implementation to extend through the next several years.

c. Choptank

Choptank implemented a new WMS with Itron, Inc., called the Interneer Intellect work management system, during 2008 and 2009. The system includes the Itron Distribution Staker package (for designing and layout of new electric distribution construction). The system coordinates with the utility's GIS mapping system and the iVue customer information system.

d. DPL and Pepco

Both utilities use Logica WMIS (Work Management Information System), and expect to upgrade to Version 4.0 during 2010. The utilities expect that the upgrade will take advantage of improved processes and functionality to standardize work efforts across utilities within Pepco Holdings, Inc.

e. SMECO

The Cooperative recently implemented a major update of its WMS software to WMIS version 2.10, with new functionality. The utility conducted study and analysis workshops to modify business processes and information flows to take advantage of the added functionality. SMECO expects that its current WMS software will serve it well and the next upgrade is expected no sooner than 2011.

5. Outage Management Communications

a. Allegheny

Allegheny provides service outage information through its IVR unit, providing calling customers concerned about an outage with an extensive list of the probable causes of the outage. Other capabilities of the IVR include providing estimated times of restoration and call-backs to customers to confirm power restoration. The utility also communicates service outage information by way of a public website at http:www.alleghenypower.com/. Numbers of service outages can be viewed by state, county or city level, and an estimated time of restoration is also given on the website. AP maintains a separate website with more detailed outage information for State Regulatory, State Emergency Management, and County 911/EMA personnel. By year-end 2009, AP intends to enhance its outage websites by adding a geographic representation of electric service outages.

b. BGE

In 2009, BGE completed an upgrade of its Predictive Dialer System, providing increased capacity and two-way communications with customers. One use of the system is to help predict the location of electric distribution facilities that are involved in service outages. The upgrade will enable communication with customers concerning estimated time for service restoration and the scheduling of planned service outages.

c. Choptank

Choptank replaced its old low band radio system with an UHF trucking radio system in 2009, to be used for communications with outage restoration crews.

d. DPL and Pepco

Last year, both utilities updated their web-based outage and work location maps to a data refresh rate of every 10 minutes, up from every 30 minutes. By early 2009, both utilities replaced the separate internet outage and work location maps with one system incorporating both functions. DPL and Pepco expect that the update will make improved and timely outage-related information available to customers and emergency management personnel.

e. SMECO

SMECO's web-based service outage map is updated automatically from its OMS at ten-minute intervals and can be accessed from http://www.smeco.coop. Press releases issued by the cooperative are included on the site. SMECO has the capability to send emails concerning expected major weather storm events to approximately 30,000 of its customers who have registered to receive the notifications. SMECO is currently investigating other methods of electronic communications to use in service outage or emergency events.

D. Distribution Planning Process

The role of an electric distribution system planner begins with identification of customer needs, both for the near term and for the future. Once identified, those needs are translated into a flexible plan involving the engineering and operations functions necessary to meet those needs. Short term planning typically focuses on system expansion to keep pace with electric load growth and maintenance or improvements related to reliability or safety of the system, with a forecast horizon of a few years. Longer term planning, with a forecast horizon of perhaps 10 to 20 years, may include expectations of new technologies and altered business climate, in addition to looking out for expanded load growth, reliability, and safety of the system.

A sampling of the largest electric distribution system projects and programs, ongoing, planned or in development by Maryland's large electric companies, follows.

1. Allegheny

- To serve a business park and surrounding development in the area near the former Ft. Ritchie U.S. Army base, AP plans to complete construction of a substation by year-end 2009.
- In 2011, AP expects to complete construction of two substations, to serve the town of Keedysville and surrounding area, and to serve the area of Lappans Crossroads.
- AP plans to complete a major upgrade of facilities at its Urbana substation in 2012 to provide additional capacity to serve the town of Urbana and the surrounding area.
- AP currently plans to complete construction in 2013 of a substation to serve the town of Poolesville and the surrounding area.
- In 2014, AP plans include upgrades to three substations. The substations supply an area west of Frederick, an area south of Frederick, and the Taneytown area.
- AP currently expects to complete a major upgrade to a substation serving an area south of Mt. Airy in 2015.

2. BGE

- Scheduled for completion in 2010, BGE plans separate substations to serve northwestern Baltimore City, eastern Anne Arundel County, the Havre de Grace and Aberdeen areas of Harford County, eastern Baltimore County, and Baltimore City's Westside & Business District.

- A substation is planned for completion in 2011 to serve Fort Meade and western Anne Arundel County.

- BGE currently expects to complete the construction of three substations in 2012. The stations are to serve an area near Laurel Mall in Howard County, the Perry Hall area of Baltimore County, and the Sykesville area of Carroll County.

- In 2013, BGE currently plans to complete the construction of three substations, to serve central Harford County, the Towson area of Baltimore County, and an area southwest of Laurel.

- Between 2014 and 2016, BGE intends to build five substations. The stations will serve the Hampstead area of Carroll County, Aberdeen Proving Ground in Harford County, the Carroll/Calverton area of Baltimore City, northeastern Baltimore City, and northern Baltimore County.

3. Choptank

- Choptank expects load growth to occur along the U.S. Route 301 corridor in Kent and Queen Anne Counties, Chestertown, Cambridge, Easton, the west side of Salisbury, and the east side of Berlin.

- Choptank is constructing a substation near Galena in Kent County to accommodate load growth along the Route 301 corridor. It is expected to be in service by December 2009.

- In 2011, Choptank expects to complete construction of a substation near Hebron in Wicomico County to serve load growth on the southwest side of Salisbury.

- A new substation to serve the Cambridge area is now planned for 2011. Currently, most of Choptank's electrical load in Dorchester County is supplied by one substation, which constitutes a single point of connection to the transmission grid. The addition of the new substation would create a backup delivery point, in addition to providing increased capacity.

4. Delmarva

- In 2010, Delmarva expects to complete a capacity upgrade of a substation serving western Kent County.

- By mid-2011, Delmarva expects to convert a feeder serving Worcester County from 4-kilovolts to 25-kilovolts (kV) operation. Distribution feeders operating at 4kV are typically aged and are less efficient than modern feeders operating at 13kV or 25kV.

- Delmarva currently plans to complete the construction of a substation to serve southern Talbot County in 2012. The utility also plans capacity upgrades for a substation serving the Massey area and for a substation serving the Bishop area in 2012.

- To serve the Salisbury area, Delmarva plans to upgrade a substation in 2013 to relieve heavy electrical loads on other nearby substations.

- Delmarva currently expects to complete the construction of two substations in 2014. One substation would serve southwestern Kent County and another would serve the Queenstown area.

5. <u>Pepco</u>

- Pepco plans to complete a capacity upgrade for a feeder serving the Sligo area of Montgomery County by mid-2011.

- By the close of 2012, Pepco plans to complete construction of a new feeder and the extension of another to meet the electricity needs of the National Harbor Development and the Gaylord National Hotel and Conference Center.

- Pepco's current plans for 2013 include a capacity upgrade of a substation serving the Colesville, Rossmoor and Fairland areas of Montgomery County.

- Pepco currently plans to complete the construction of two substations in 2014. One substation would serve the Bureau of Standards, Hunting Hill and Shady Grove areas of Montgomery County. The other substation would supply the Westphalia Town Center and the Melwood and Forrestville areas of Prince George's County.

- To accommodate the projected demand for electricity in the Beltsville area of Prince George's County and the Fernwood Road area of Montgomery County, Pepco plans to complete the construction of two substations by year-end 2015.

6. <u>SMECO</u>

- In 2010, SMECO expects to complete construction of a substation and to energize three new feeders from the station to serve the Huntington area of Calvert County. The substation could support at least four additional feeders for future use. The cooperative also plans to upgrade two existing substations in order to address load growth and provide backup supply for service outages, in 2010. The upgraded substations will serve the Saint Andrews area of Saint Mary's County and the Saint Charles Development area of Saint Charles County.

- SMECO currently plans to upgrade two substations in 2011. One of the stations serves the Leonardtown area of Saint Mary's County. The other station serves the area near Vivian Adams Drive in Charles County. To provide support during service outages, SMECO intends to purchase a new mobile substation in 2011. The new mobile unit is capable of backing up any large distribution substations that would be temporarily out of service for repairs or maintenance. SMECO currently owns two other mobile substations.

VIII. MARYLAND ELECTRICITY MARKETS

The Electric Customer Choice and Competition Act of 1999 established the legal framework for the restructuring and revised regulation of the electric industry in Maryland. The Electric Act altered the Commission's role relative to electricity generation and provided that retail electric choice would be available to all customers. Beginning on July 1, 2000, all retail electric customers of IOUs in the State were given the opportunity to choose their electricity supplier. As of July 1, 2003, customers of Maryland's electric cooperatives have had the right to choose suppliers under a separate schedule adopted by the Commission. Customers of Maryland's municipal electric utilities will be allowed to choose suppliers on a timetable established in part by the municipal utilities.

A. Status of Retail Electric Choice in Maryland

Customers shopping for electricity in Maryland may choose to buy electricity from a competitive supplier or to take standard offer service from their local electric company. This framework was established by the Electric Customer Choice and Competition Act of 1999. The Electric Act deregulated the pricing of electric generation and opened retail markets to competitive suppliers. Opening retail markets for competition has attracted competitive suppliers to Maryland. As of December 31, 2009, the Commission has issued 47 electricity supplier licenses and 59 electricity broker licenses.

An examination of the number of customers using a competitive supplier indicates that the transition from utility-supplied generation service to electric competition in Maryland has initially excluded residential customers, of whom only 5.0% (up from 2.9% in 2008) take service from a competitive retailer. However, until this past year, competitive suppliers have not been able to consistently make offers below SOS rates for the residential class. In 2009, residential switching has picked up compared with previous years as the number of Residential Choice customers has increased by 79% statewide.[75] The increase in switching is likely due to the availability of savings over the Standard Offer Service rates. Residential electricity offers have been observed to be on the order of 10% below the cost of Standard Offer Service, saving an average customer about $150 per year. There are three retailers making such offers at this time.[76]

The following table illustrates the increase in residential customer switching during 2009. For many years, residential switching has been relatively unchanged. Year 2009 was different, in particular in the BGE service territory. BGE's residential switching percentage almost

75 Residential switching increased from 55,025 to 98,599 during 2009.

76 Washington Gas Energy Services, Dominion Retail, Inc., BGE HOME (Constellation Electric).

doubled and now leads the Pepco service territory in the total number of switched customers. Pepco had experienced a higher number of switched customers in previous years, in spite of a residential customer count less than half of BGE's. Pepco still has the highest percentage of switched customers (8.3%) of any service territory in Maryland. The much larger (over 6700%) annual increase in switching in the Allegheny Power ("AP") service territory is likely to have been influenced by the removal of the rate caps on AP's SOS rates in January of 2009. Prior to 2009, AP had almost no residential switching. AP now has just over 1% of customers on retail choice.

<u>Table VIII.A.1: Residential Customers Enrolled in Retail Supply at Year End</u>

	2008	2009	Annual % Increase
BGE	26,944	53,126	97%
Pepco	27,001	40,267	49%
DPL	1,039	2,463	137%
AP	40	2,743	6758%
Md. Total	55,024	98,599	79%

Between December 2005 and December 2009, the total number of customers statewide served by electricity suppliers increased from 39,527 to 169,908 customers. The number of customers served by electricity suppliers in BGE's service territory increased from 3,932 (October 2005) to 93,469 (December 2009).

Table VIII.A.2: Electric Choice Enrollment in Maryland[77]

Number of Customers Served by Competitive Electricity Suppliers[78]

Utilities	Residential	Small C&I[79]	Mid C&I[80]	Large C&I[81]	All C&I	Total
AP	2,743	4,068	2,657	117	6,842	9,585
BGE	53,126	25,877	13,867	609	40,353	93,479
Delmarva	2,463	4,139	2,367	69	6,575	9,038
Pepco	40,267	8,758	8,284	497	17,539	57,806
Total	**98,599**	**42,842**	**27,175**	**1,292**	**71,309**	**169,908**

Percentage of Peak Load Obligation Served by Competitive Electricity Suppliers

Utilities	Residential	Small C&I	Mid C&I	Large C&I	All C&I	Total
AP	0.0%	20.9%	59.8%	86.9%	67.1%	32.5%
BG&E	5.3%	24.3%	68.2%	92.1%	74.0%	39.3%
Delmarva	2.0%	28.6%	67.3%	96.7%	68.1%	33.3%
Pepco	9.6%	28.0%	68.8%	96.9%	77.0%	45.5%
Total	**5.6%**	**25.3%**	**67.4%**	**93.1%**	**73.8%**	**39.9%**

Source: Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report*, Month Ending December 2009. The Electric Choice Enrollment Report is updated monthly and can be obtained at the following website: http://www.psc.state.md.us/psc/home.htm.

B. Standard Offer Service

Standard Offer Service is electricity supply service sold by electric utility companies to any customer who does not choose a competitive supplier. The electric companies provide the service by purchasing wholesale power contracts, typically of 2-year lengths, through sealed bid procurements. Since the end of residential price freeze service in July 2004, SOS rates have

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77 Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report*, Month Ending December 2009. The Electric Choice Enrollment Report is updated monthly and can be obtained at the following website: http://www.psc.state.md.us/psc/home.htm.

78 As of December 31, 2009, the following list indicates the number of companies in Maryland that have registered on the Commission's website as actively soliciting new customers in any service territory: 11 serving residential load, 53 serving industrial load, 57 serving commercial load, and 16 serving other types of load (such as government).

79 Small C&I customers are commercial or industrial customers with demands less than or equal to 25 kW. These customers are eligible for "Type I" fixed price utility SOS if they do not switch to a supplier.

80 Mid-sized C&I customers are commercial or industrial customers with demands greater than 25kW, the level for small C&I service (Type I SOS) but less than 600 kW. These customers are eligible for “Type II” fixed price utility SOS if they do not switch to a supplier. See discussion of Case Nos. 9037 and 9056 to see more information on the Type II customer class.

81 Large C&I customers are commercial or industrial customers with demands equal to or greater than 600 kW. These customers are no longer eligible for “Type III” SOS and receive hourly priced service (based on PJM hourly LMP) if they do not switch to a supplier.

experienced price increases such that average total annual residential electricity expenses have increased on the order of 80% over pre-restructuring rates for the year beginning June 2008.[82]

During the 2007 session, the General Assembly passed Senate Bill 400[83], legislation that modified some portions of Section 7-510 of the PUC Article to require wholesale power procurements which were "designed to obtain the best price for residential and small commercial customers in light of prevailing market conditions at the time of the procurement and the need to protect these customers against excessive price increases."[84]

On August 16, 2007, the Commission docketed Case No. 9117, *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland* to consider other approaches to supply SOS in a competitive process under this standard. In particular, the Commission directed parties to present testimony that would compare the actively managed portfolio approach of SMECO to the RFP process used by the major IOUs. Additionally, the Commission wanted to consider a Direct Energy Services, LLC proposal to serve Electric Universal Service Program participants on an aggregated basis. On September 25, 2007, the Commission initiated Phase II of the case to consider proposals for procedures to be used to solicit bids for cost-effective energy efficiency and conservation programs and services and to obtain comment on the option of directing electric companies to build, acquire or lease peak-load or other generating plants to avert a potential reliability problem in Maryland. Initial and reply testimony was filed in September 2007 for Phase I and in October 2007 for Phase II. Hearings for both phases were held during October and November 2007. The Commission issued Order No. 82105 on July 3, 2008 directing each utility to file an evaluation of procurement plans using contracts of 10-15 years in length. The utilities were directed to file by October 1, 2008. Parties to the Case were to file comments in reply to those plans by December 5, 2008. The Commission held hearings in mid-December 2008 to consider the plans and comments.

On July 14, 2009, the Commission provided notice to the Case No. 9117 parties to comment on the July 6, 2009 motion of CPV Maryland, LLC ("CPV") for *(A)n Order Requiring Investor-Owned Utilities to Enter into Long-Term Contracts for the Sale of Power from CPV Maryland, LLC's Proposed 640 MW Generating Facility in Charles County, Maryland and Request for Expedited Treatment*. On September 29, 2009 the Commission issued Order No. 82936 that recognized the many issues that the parties' comments raised regarding the evaluation and terms of long term contracting for generation and docketed Case No. 9214, *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service* for the purpose of evaluating specific generation proposals. Proposals were to be submitted by December 1, 2009. In response to a Commission Staff request for clarification of the information that should be provided in the December 1 proposals, on October 15, 2009 the Commission requested comments from the parties. On November 10, 2009 the Commission issued a tolling order that suspended the December 1, 2009 deadline for proposals pending the Commission's determination on clarifications to Order No. 82936.

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82 Case No. 9064 Commission Staff Report on SOS, dated June 12, 2008, page 16.

83 Chapter 549, 2007 Maryland Laws.

84 PUC Article § 7-510(c)(4)(ii).

On November 14, 2003, the Commission docketed Case Nos. 8985 and 8987 in order to address the SOS procurement issue for SMECO and Choptank, respectively. On September 29, 2004, the Commission issued Order No. 79503 in Case No. 8985 to address SOS for SMECO during the 2005 to 2008 period. The Order permits SMECO to procure power for its SOS service on the wholesale market using a managed portfolio approach for the 2005 through May 31, 2008 period. The Commission subsequently approved extension of the use of SMECO's portfolio through May 31, 2010 in Order 80839.[85] On April 25, 2005, the Commission issued Order No. 79922 in Case No. 8987 to address SOS for Choptank. In this Order, the Commission adopted a settlement regarding continued provision of SOS by Choptank, including continued procurement of full-requirements wholesale service through the Old Dominion Electric Cooperative and a modification of its power cost adjustment mechanism. The original time period during which Choptank will provide SOS was extended by five years, beginning on July 1, 2005, and ending on June 30, 2015.

IX. REGIONAL ENERGY ISSUES AND EVENTS

A. Overview of PJM, OPSI and Reliability First

The flow of electricity and the electricity markets are undeniably regional concepts. Maryland is not an energy island - the transmission lines located within Maryland do not terminate at our borders, but rather are connected to the transmission lines in adjoining states.

The entire State of Maryland resides within PJM, the regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. FERC is responsible for approving tariff changes proposed by PJM, which wholesale market entities operating in Maryland must abide by as a member of PJM. In addition, the Maryland Public Service Commission is a member of OPSI, an organization of statutory regulatory agencies in the 13 states and the District of Columbia that form PJM. Finally, Maryland falls within the boundaries of Reliability First, one of eight regional entities approved by NERC as of January 1, 2006 to develop and enforce regional reliability standards.

1. PJM Interconnection, LLC

PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM is the largest centrally dispatched grid in North America. PJM has more than 500 members, including power generators, transmission owners, electricity distributors, other suppliers and end-use customers.[86] The Maryland Public Service Commission is not a member of PJM (meaning it is unable to cast a vote); however, it does monitor proceedings at PJM.

PJM keeps the electricity supply and demand in balance by instructing power producers on the amount of energy that should be generated and by adjusting import and export

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85 Issued July 14, 2007.

86 PJM, Company Overview, Available: http://www.pjm.com/about-pjm/who-we-are/company-overview.aspx

transactions. PJM dispatches about 163,500 megawatts (MW) of generating capacity over 56,350 miles of transmission lines.[87] PJM exercises a broader reliability role than that of a local electric utility. PJM system operators conduct dispatch operations and monitor the status of the grid. This gives PJM a big-picture view of regional conditions and reliability issues, including those in neighboring systems.

PJM manages a sophisticated regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations and transmission lines. The PJM region has an area of 168,500 square miles, a population of about 51 million and a peak demand of 144,644 megawatts.[88]

2. Organization of PJM States, Inc. ("OPSI")

The purpose of OPSI is to maintain an organization of statutory regulatory agencies in the 13 states and the District of Columbia within PJM. OPSI's activities include, but are not limited to, coordinating activities such as data collection, issue analyses, and policy formulation related to PJM, its operations, its market monitor, and related FERC matters.[89] OPSI provides a means for the PJM states to act in concert with one another when it is deemed to be in the common interest of their consumers. Actions of OPSI, however, do not bind individual commissions or the states they represent.

Each state commission has a member on the OPSI Board of Directors. Chairman Nazarian of the Commission assumed the OPSI Presidency in 2009 and will relinquish it in 2010. The OPSI Annual Board Meeting was held in Annapolis, Maryland in October 2009, during which revisions to PJM's energy and capacity markets, demand response and climate change legislation, among other issues, were discussed. The Maryland Commission continues to be a very active participant in OPSI and participates on several of its committees.

3. Reliability First Corporation

Reliability First is a corporation that was organized to establish more uniformity of standards and compliance conformance across a broad geographical area that encompasses multiple systems and market operators, including most of PJM (and all of Maryland). As the transmission system in Maryland is connected to the transmission systems of adjoining states, the transmission system within the larger area of PJM is connected to the transmission systems of adjoining control areas.

The purpose of Reliability First is to preserve and enhance electric service reliability and security of the interconnected electric system and to be a regional entity under the framework of NERC. FERC continues to have oversight in enforcing compliance among bulk system owners, operators, and transmission system users.

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87 Id.
88 Id.
89 Organization of PJM States, Available: http://www.opsi.us/

B. PJM Summer Peak Events of 2008 and 2009

Peak load is maximum load usage during a specified period of time. Table IX.B.1 provides the coincident peaks as measured by PJM to illustrate the maximum amount of MW usage in PJM at a particular time during a 12-month period. PJM is a summer peaking region, meaning that it has historically experienced its peak loads during hot summer days when air-conditioning usage increases to meet cooling demand. PJM measures energy usage over an hour, accordingly, the data in the table below means the peak occurred sometime in the 59 minutes preceding the hour listed.

Table IX.B.1: Summer 2008 and Summer 2009 Coincident Peaks and Zone LMP

Summer 2008 Coincident Peaks				**Zone LMP During the Peak**				
Day	**Date**	**Hour**	**MW**	**AP**	**BGE**	**DPL**	**PEPCO**	**PJM**
Monday	6/9/2008	17:00	130,792	$348.69	$311.69	$358.30	$358.30	$265.17
Thursday	7/17/2008	17:00	129,790	$160.08	$231.82	$205.24	$239.30	$182.98
Friday	7/18/2008	17:00	129,429	$205.42	$274.84	$230.30	$251.63	$197.57
Monday	7/21/2008	17:00	128,813	$196.60	$212.53	$251.99	$211.89	$199.41
Tuesday	6/10/2008	16:00	128,598	$253.81	$544.55	$482.18	$522.57	$335.04
Summer 2009 Coincident Peaks				**LMP During the Peak**[90]				
Day	**Date**	**Hour**	**MW**	**AP**	**BGE**	**DPL**	**PEPCO**	**PJM**
Monday	8/10/2009	17:00	126,944	$104.30	$104.90	$126.00	$138.98	$85.69
Tuesday	8/11/2009	17:00	120,708	$54.35	$55.21	$50.09	$79.95	$49.04
Monday	8/17/2009	17:00	121,933	$65.28	$70.44	$72.64	$58.55	$60.93
Tuesday	8/18/2009	16:00	122,369	$63.77	$153.48	$130.13	$155.48	$89.65
Thursday	8/20/2009	16:00	120,112	$88.99	$113.52	$111.51	$115.58	$83.14

The 2009 summer peak events in PJM were lower than the summer peak events that occurred in 2008. Table IX.B.1 above shows the Summer 2008 and 2009 coincident peaks in PJM and the average real time LMP by zones located in Maryland during that time period. The Summer 2008 peak was 130,792 MW and occurred on June 9, 2008 during the hour ending 5:00 PM Eastern Daylight Time.[91] The Summer 2009 peak was 126,944 MW and occurred on August 10, 2009 during the hour ending 5:00 PM Eastern Daylight Time.[92]

The amount of capacity procured in PJM's Reliability Pricing Model ("RPM") is roughly based upon a forecast of the peak load projected by PJM for a particular year, plus a reserve margin. RPM works in conjunction with PJM's Regional Transmission Expansion Process ("RTEP") to ensure reliability in the PJM region for future years.

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90 PJM, Markets & Operations, Daily Real-Time LMP Files, Available: http://www.pjm.com/markets-and-operations/energy/real-time/lmp.aspx

91 PJM, Planning, Available: http://www.pjm.com/planning/res-adequacy/downloads/summer-2008-peaks-and-5cps.pdf

92 PJM, Planning, Available: http://www.pjm.com/~/media/planning/res-adeq/load-forcast/summer-2009-pjm-scps-and-w-n-zonal-peaks.ashx

C. PJM's Reliability Pricing Model

As a means of ensuring reliability of the electric system in the RTO, PJM annually conducts a long-term planning process that compares the potential available generation located within the RTO and the import capability of the RTO against the estimated demand of customers within the RTO and establishes the amount of generation and transmission required to maintain the reliability of the electric grid within PJM. Using this information, PJM evaluates offers from generators and other resources three years in advance to be available for a one year delivery period (up to three years for new generation) through the RPM Base Residual Auction ("BRA").[93] Once PJM completes its RTEP and conducts the RPM BRA, PJM is in a position to evaluate the reliability of its system. PJM must operate the transmission system to meet reliability criteria established by the FERC and administered by the NERC.

As an alternative to participating in the RPM auctions, an LSE can meet its capacity requirement by certifying to PJM that the LSE has undertaken a multi-year commitment to completely cover its forecasted load over the time period. Under this procurement method, known as the Fixed Resource Requirement Election ("FRR"), an LSE meets its capacity requirement via bilateral agreements and self-supply resources. In addition, the LSE does not pay RPM capacity prices, nor do the committed supply resources receive RPM capacity prices.

PJM held the BRA for the 2012/2013 delivery period in May 2009. PJM calculated the RTO reliability requirement to be 133,732.4 MW, which includes a [16.2] percent reserve margin. However, as a result of the administratively determined downward sloping demand curve-the Variable Resource Requirement-more resources than needed cleared the market. In 2009, 136,143.5 MW cleared the BRA which essentially increased the reserve margin to 20.9 percent. This means 2411 MW in excess of the reliability requirement were procured in the BRA. Approximately 9229 MW of excess capacity was offered into the 2012/2013 BRA (i.e., this capacity did not clear); accordingly, for the 2012/2013 delivery year, and approximately 11,640 MW of capacity in excess of the RTO reliability requirement was offered into the BRA.[94]

SWMAAC, the LDA of which BGE and Pepco are a part, seperated for the 2012/2013 delivery year. However, MAAC, of which SWMAAC is a part, did constrain due to transmission limitations.[95] As a result of these limitations and higher priced generation located within MAAC as compared to the rest of the RTO, the LSEs within MAAC will pay higher capacity costs than the rest of the RTO for that time period. The LDA in which Delmarva is located also constrained and will also pay a higher capacity cost than the rest of the RTO. The capacity clearing prices for IOUs in Maryland are set forth in the table below.

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93 PJM, Markets & Operations, Reliability Pricing Model, Available: http://www.pjm.org/markets-and-operations/rpm.aspx

94 PJM, Markets & Operations, Available http://www.pjm.org/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx

95 Id.

Table IX.C.1: RPM Clearing Prices

Delivery year	Rest-of-RTO	SWMAAC	EMAAC	DPL South
	Includes all other LDAs, including "Western PJM," which contains Allegheny Power	Pepco BGE	Delmarva, North of Chesapeake and Delaware Canal	Delmarva, South of Chesapeake and Delaware Canal
2007/08	$40.80	$188.54	$197.67	$197.67
2008/09	$111.92	$210.11	$148.80	$148.80
2009/10	$102.04	$237.33	$191.32	$191.32
2010/11	$174.29	$174.29	$174.29	$186.12
2011/12	$110.00	$110.00	$110.00	$110.00
2012/13	$16.46	$133.37	$139.73	$222.30

D. Region-Wide Demand Response in PJM Markets

Demand Response continues to be actively promoted within the wholesale electricity markets. PJM provides the opportunity for DR to be bid into the Energy, Capacity, Synchronized Reserve, and Regulation markets. 9,874 MW of demand resources were offered into the 2012/2013 BRA which represents an increase of 496% over the amount offered into the 2011/2012 BRA.[96] Of that amount, 7,047.3 MW cleared and 4,723.8 MW was located in constrained regions, including Maryland.[97]

PJM has two basic energy and capacity market demand response programs: the Economic Load Response Program and the Emergency Load Program. The goal of these programs is to provide economic incentives for end-use customers to curtail the electricity usage in the circumstances of either peak periods or unexpected outages.

1. Economic Load Response Program

The PJM Economic Load Response Program (ELRP) is a PJM-managed accounting mechanism that provides for payment of the real savings that result from load reductions to the load reducing customer. This is a voluntary program that allows customers the opportunity to reduce their load and receive payments based on day-ahead LMP. These payments are the difference between the zonal LMP and the customer's retail rates.

In 2009, PJM filed a proposal with FERC intended to replace the enhancement component of its ELRP, which sunsets at the end of 2007. PJM proposed to: (1) change the compensation for demand reductions from the current rate of (LMP minus (Generation + Transmission)) to (LMP minus Generation); (2) impose charges upon fixed price customers and day-ahead LMP customers that self-schedule but fail to reduce consumption; and (3) provide

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[96] Id.

[97] Id. PJM hypothesized that one of the reasons for the large increase in the amount of demand response resources offered into the BRA was the elimination of the Interruptible Load for Reliability product beginning with the 2012/2013 delivery period.

"incentive" payments to participants when they respond during the highest-priced nine percent of hours up to 1000 MW in the aggregate of reductions from small and medium-sized end-use customers.[98] The Commission has filed comments with the FERC opposing PJM's proposal, specifically asserting that participants should receive full LMP and the enhancements should not be capped at the highest-priced 9% of hours or 1000 MW total.[99]

2. Emergency Load Program

The PJM Emergency Load Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. The Emergency-Capacity Only program provides RPM payments for reducing capacity and reduction is mandatory. The Emergency-Full program provides both RPM payments and energy payments for reducing capacity, and the reduction is mandatory. The Emergency-Energy Only program provides energy payments to end-use customers for voluntarily reducing load during an emergency event. The energy payment is the zonal LMP.

X. PROCEEDINGS BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Approximately 80 percent of the typical Maryland ratepayer's electric bill reflects the wholesale cost of the electricity he or she uses – a cost that, under restructuring, the PSC no longer regulates. Accordingly, the PSC has devoted substantial time, effort and resources to serving as an advocate for Maryland ratepayers at PJM and before the Federal Energy Regulatory Commission ("FERC").

The Commission focused its efforts in 2008 on market rules and pricing issues. Retail electric service and prices in Maryland are affected by prices and practices relating to the provision of generation and transmission at the wholesale level, over which FERC has authority under the Federal Power Act. Currently, suppliers providing generation to serve Maryland load have market-based rate ("MBR") authority, which means that they are allowed to charge rates not subject to FERC's approval (so long as the supplier lacks market power or its market power has been sufficiently mitigated in the market to be served). Whether they are established by bilateral contract or by the winning bid in a market run by PJM, rates for wholesale generation sold by suppliers with MBR authority must be just and reasonable under the Federal Power Act.

During 2008, the Commission filed complaints asking FERC to require PJM to lift the exemptions from offer-capping applicable to certain interfaces and generators, and to provide a remedy for unjust and unreasonable RPM Transitional Period Auction Rates (for capacity prices established in the transition auctions for delivery years beginning in June 2008, 2009, and 2010), to prohibit PJM from collecting charges based on those rates (which the Commission believes are unjust and unreasonable), or to direct refunds of capacity charge overpayments demanded by PJM resulting from them.

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98 FERC docket no. EL09-68-000 PJM filing 8-26-2009.

99 Comments of the PSC; FERC Docket No. EL09-68-000 PJM filing 8-26-2009: pages 5-9.

In 2009, the Commission continued to pursue its complaint relating to RPM Transitional Period Auction Rates. Following the FERC's dismissal of the complaint in September 2008, the Commission and others requested rehearing. The request for rehearing was denied on June 18th resulting in the Commission filing a petition for judicial review in this matter, which will be heard in the U.S. Court of Appeals for the District of Columbia Circuit .

Additionally, the Commission has continued to protest efforts by PJM to impose limitations on the role of the market monitor; as well, the Commission continues to challenge FERC to adopt a more standards-based approach for awarding transmission rate incentives, objecting to projects that primarily support local reliability and lack clear regional benefits.

The Commission will continue to play an informed and aggressive role in advocating for Maryland's energy interests in the PJM stakeholder process and before FERC.

APPENDIX

The Appendix contains a compilation of data provided by Maryland's electric companies, including the number of customers, sales by customer class, and typical utility bills, as well as forecasted peak demand and electricity sales over the next fifteen years, by utility. It also includes a list of all licensed electricity and natural gas suppliers and brokers in Maryland, renewable energy projects, planned transmission enhancements, and power purchase agreements for each utility.

Table A-1: Utilities Providing Retail Electric Service in Maryland

Utility	Service Territory
A&N Electric Cooperative	Smith Island in Somerset County
Baltimore Gas & Electric Company	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	Town of Berlin.
Choptank Electric Cooperative	Portions of the Eastern Shore.
Delmarva Power & Light Company	Major portions of ten counties primarily on the Eastern Shore.
Easton Utilities Commission	City of Easton.
Hagerstown Municipal Electric Light Plant	City of Hagerstown.
Potomac Edison Company	Parts of western Maryland.
Potomac Electric Power Company	Major portions of Montgomery and Prince George's Counties.
Somerset Rural Electric Cooperative	Northwestern corner of Garrett County.
Southern Maryland Electric Cooperative	Charles and St. Mary's Counties; portions of Calvert and Prince George's Counties.
Thurmont Municipal Light Company	Town of Thurmont
Town of Williamsport	Town of Williamsport

Source: Table 1 in Company data responses to the Commission’s 2009 data request for the Ten-Year Plan.

Table A-2: Number of Customers by Customer Class (As of December 31, 2008)

Utility/Co.	System-wide						Maryland					
	Residential	Commercial	Industrial	Other	Sales for Resale	Total	Residential	Commercial	Industrial	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**
Berlin	1,955	287	115	19	0	2,376	1,955	287	115	19	0	**2,376**
BGE	1,108,503	117,633	5,345	0	0	1,231,481	1,108,503	117,633	5,345	0	0	**1,231,481**
Choptank	47,081	4,639	20	262	0	52,002	47,081	4,639	20	262	0	**52,002**
DPL	438,005	58,275	509	639	0	497,428	172,766	25,573	250	272	0	**198,861**
Easton	8,073	2,081	0	95	0	10,249	8,073	2,081	0	95	0	**10,249**
Hagerstown	15,126	2,182	121	0	0	17,429	15,126	2,182	121	0	0	**17,429**
PE/AP	417,562	57,682	6,307	792	6	482,349	218,661	27,339	2,835	345	3	**249,183**
PEPCO	692,987	73,434	12	134	0	766,567	472,874	46,756	11	102	0	**519,743**
SMECO	133,560	13,204	5	267	0	147,036	133,560	13,204	5	267	0	**147,036**
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
Thurmont	2,460	339	11	45	0	2,855	2,460	339	11	45	0	**2,855**
Williamsport	855	68	36	45	0	1,004	855	68	36	45	0	**1,004**
Total	**2,866,167**	**329,824**	**12,481**	**2,298**	**6**	**3,210,776**	**2,181,914**	**240,101**	**8,749**	**1,452**	**3**	**2,432,219**

Source: Table 2 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: A&N and Somerset did not provide a response to the Commission's data request.

Table A-3: Average Sales by Customer Class (As of December 31, 2008; GWh)

Utility/Co.	System-wide						Maryland					
	Residential	Commercial	Industrial	Other	Sales for Resale	Total	Residential	Commercial	Industrial	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**
Berlin	2	0	1	0	0	3	2	0	1	0	0	**3**
BGE	1,085	1,308	270	0	0	2,664	1,085	1,308	270	0	0	**2,664**
Choptank	54	18	6	0	0	78	54	18	6	0	0	**78**
DPL	420	440	222	4	0	1,087	175	145	35	1	0	**357**
Easton	9	13	0	1	0	22	9	13	0	1	0	**22**
Hagerstown	13	6	10	0	0	29	13	6	10	0	0	**29**
PE/AP	523	298	274	2	62	1,159	271	171	129	1	39	**610**
PEPCO	642	1,467	60	61	0	2,230	483	719	38	27	0	**1,267**
SMECO	169	93	16	0	0	279	169	93	16	0	0	**279**
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
Thurmont	3	1	2	0	0	7	3	1	2	0	0	**7**
Williamsport	1	0	1	0	0	2	1	0	1	0	0	**2**
Total	**2,921**	**3,644**	**864**	**68**	**62**	**7,560**	**2,266**	**2,473**	**510**	**31**	**39**	**5,319**

Source: Table 3 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: Data were rounded to whole numbers. A&N and Somerset did not provide a response to the Commission's data request.

Table A-4: Typical Monthly Utility Bills in Maryland, (Winter 2009)

	Energy Use (kWh)			Typical Bill ($)			Revenue ($/kWh)		
Utility/Co.	**Residential**	**Commercial**	**Industrial**	**Residential**	**Commercial**	**Industrial**	**Residential**	**Commercial**	**Industrial**
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Berlin	1,000	1,000	80,000	$169.49	$202.10	$11,922.52	$0.1695	$0.2021	$0.1490
BGE	750	12,500	200,000	$119.00	$1,757.00	$3,585.00	$0.1587	$0.1406	$0.0179
Choptank	750	12,500	200,000	$109.10	$1,630.06	$23,180.26	$0.1455	$0.1304	$0.1159
DPL	750	12,500	200,000	$121.64	$1,834.09	$19,407.58	$0.1622	$0.1467	$0.9704
Easton	750	12,500	N/A	$87.49	$1,490.96	N/A	$0.1167	$0.1193	N/A
Hagerstown	750	12,500	200,000	$71.21	$1,255.41	$17,256.65	$0.0950	$0.1004	$0.0863
PE/AP	1,724	3,403	15,265	$173.45	$363.20	$1,261.10	$0.1006	$0.1067	$0.0826
PEPCO	750	12,500	200,000	$113.38	$1,268.44	$18,258.52	$0.1512	$0.1015	$0.0913
SMECO	750	12,500	200,000	$118.47	$1,659.89	$23,157.37	$0.1580	$0.1328	$0.1158
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Thurmont	750	12,500	200,000	$130.55	$987.09	$14,638.96	$0.1035	$0.0960	$0.0904
Williamsport	900	1,800	200,000	$88.18	$176.39	$1,952.75	$0.0968	$0.0955	$0.0958

Source: Table 8 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: A&N and Somerset did not provide a response to the Commission’s data request
N/A: Data are not available.

Table A-5(a): System-Wide Peak Demand Forecast (Net of DSM Programs: MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	SMECO	Thurmont	Williams-port	Total
2009	3	7,044	219	3,951	67	64	2,965	6,893	801	20	5	**22,031**
2010	3	6,790	221	3,958	68	62	3,008	6,847	824	20	5	**21,805**
2011	3	6,653	227	4,001	70	60	3,057	6,630	842	20	5	**21,567**
2012	3	6,392	233	4,115	71	60	3,100	6,618	860	20	5	**21,476**
2013	3	6,220	238	4,189	72	60	3,137	6,682	878	20	5	**21,504**
2014	3	6,250	247	4,258	74	61	3,173	6,721	894	20	5	**21,705**
2015	4	6,252	253	4,317	75	61	3,217	6,755	912	20	5	**21,870**
2016	4	6,344	256	4,393	76	61	3,270	6,821	929	20	5	**22,179**
2017	4	6,439	262	4,475	78	61	3,325	6,900	945	20	5	**22,514**
2018	4	6,536	268	4,552	79	61	3,376	6,979	963	20	5	**22,843**
2019	4	6,634	273	4,645	80	62	3,432	7,066	979	20	5	**23,199**
2020	4	6,736	278	4,732	82	62	3,476	7,154	996	20	5	**23,545**
2021	5	6,844	283	4,822	83	62	3,532	7,230	1,013	20	5	**23,898**
2022	5	6,957	288	4,905	84	62	3,592	7,306	1,029	20	5	**24,253**
2023	5	7,074	292	4,995	86	62	3,656	7,383	1,045	20	5	**24,623**
Change (2009-2023)	**2**	**30**	**73**	**1,044**	**19**	**-2**	**691**	**490**	**244**	**1**	**0**	**2,592**
Percentage Change	**75.0%**	**0.4%**	**33.3%**	**26.4%**	**28.1%**	**-2.5%**	**23.3%**	**7.1%**	**30.5%**	**4.3%**	**0.0%**	**11.8%**
Annual Growth Rate	**4.1%**	**0.0%**	**2.1%**	**1.7%**	**1.8%**	**-0.2%**	**1.5%**	**0.5%**	**1.9%**	**0.3%**	**0.0%**	**0.8%**

Source: Table 4 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers for presentation in the table but calculations were based on actual numbers from data responses. A&N and Somerset did not provide a response to the Commission’s data request; moreover, Hagerstown, PE/AP, Thurmont and Williamsport are winter peaking service territories, while Berlin, BGE, Choptank, DPL, Easton, Pepco and SMECO are summer peaking service territories.

Table A-5(b): Maryland Peak Demand Forecast (Net of DSM Programs; MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE/AP	Pepco	SMECO	Thurmont	Williams-port	Total
2009	3	7,044	219	891	67	64	1,529	3,589	801	20	5	**14,230**
2010	3	6,790	221	875	68	62	1,534	3,511	824	20	5	**13,913**
2011	3	6,653	227	813	70	60	1,544	3,240	842	20	5	**13,476**
2012	3	6,392	233	811	71	60	1,557	3,175	860	20	5	**13,187**
2013	3	6,220	238	803	72	60	1,566	3,189	878	20	5	**13,054**
2014	3	6,250	247	804	74	61	1,571	3,190	894	20	5	**13,119**
2015	4	6,252	253	809	75	61	1,584	3,189	912	20	5	**13,162**
2016	4	6,344	256	826	76	61	1,608	3,223	929	20	5	**13,352**
2017	4	6,439	262	845	78	61	1,632	3,265	945	20	5	**13,555**
2018	4	6,536	268	863	79	61	1,653	3,306	963	20	5	**13,758**
2019	4	6,634	273	884	80	62	1,677	3,352	979	20	5	**13,970**
2020	4	6,736	278	904	82	62	1,696	3,398	996	20	5	**14,181**
2021	5	6,844	283	925	83	62	1,721	3,438	1,013	20	5	**14,398**
2022	5	6,957	288	944	84	62	1,751	3,478	1,029	20	5	**14,623**
2023	5	7,074	292	964	86	62	1,783	3,519	1,045	20	5	**14,855**
Change (2009-2023)	**2**	**30**	**73**	**73**	**19**	**-2**	**254**	**-70**	**244**	**1**	**0**	**625**
Percentage Change	**75%**	**0.4%**	**33.3%**	**8.2%**	**28.1%**	**-2.5%**	**16.6%**	**-2.0%**	**30.5%**	**4.3%**	**0.0%**	**4.4%**
Annual Growth Rate	**4.1%**	**0.0%**	**2.1%**	**0.6%**	**1.8%**	**-0.2%**	**1.1%**	**-0.1%**	**1.9%**	**0.3%**	**0.0%**	**0.3%**

Source: Table 4 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Notes: The data were rounded to whole numbers for presentation in the table but calculations were based on actual numbers from data responses. A&N and Somerset did not provide a response to the Commission's data request; moreover, Hagerstown, PE/AP, Thurmont and Williamsport are winter peaking service territories, while Berlin, BGE, Choptank, DPL, Easton, Pepco and SMECO are summer peaking service territories.

Table A-5(c): System-Wide Peak Demand Forecast (Gross of DSM Programs; MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE/AP	Pepco	SMECO	Thurmont	Williams-port	Total
2009	10	7,345	229	3,972	67	64	2,971	6,960	812	20	5	**22,453**
2010	10	7,373	231	4,002	68	62	3,025	7,026	835	20	5	**22,656**
2011	10	7,531	237	4,138	70	60	3,088	7,141	853	20	5	**23,151**
2012	10	7,727	243	4,289	71	60	3,143	7,252	871	20	5	**23,690**
2013	10	7,868	249	4,395	72	60	3,193	7,358	889	20	5	**24,118**
2014	10	8,015	257	4,483	74	61	3,241	7,437	905	20	5	**24,506**
2015	11	8,144	263	4,554	75	61	3,296	7,512	923	20	5	**24,862**
2016	11	8,271	267	4,630	76	61	3,346	7,578	940	20	5	**25,204**
2017	11	8,395	272	4,712	78	61	3,399	7,657	956	20	5	**25,565**
2018	11	8,518	278	4,789	79	61	3,448	7,736	974	20	5	**25,918**
2019	11	8,640	283	4,882	80	62	3,501	7,823	990	20	5	**26,296**
2020	11	8,761	288	4,969	82	62	3,542	7,911	1,007	20	5	**26,657**
2021	11	8,883	293	5,059	83	62	3,592	7,987	1,024	20	5	**27,019**
2022	12	9,008	298	5,142	84	62	3,643	8,063	1,040	20	5	**27,377**
2023	12	9,134	302	5,232	86	62	3,697	8,140	1,056	20	5	**27,745**
Change (2009-2023)	**2**	**1,789**	**73**	**1,260**	**19**	**-2**	**726**	**1,180**	**244**	**1**	**0**	**5,292**
Percent Change	**21.6%**	**24.4%**	**31.9%**	**31.7%**	**28.1%**	**-2.5%**	**24.4%**	**17.0%**	**30.1%**	**4.3%**	**0.0%**	**23.6%**
Annual Growth Rate	**1.4%**	**1.6%**	**2.0%**	**2.0%**	**1.8%**	**-0.2%**	**1.6%**	**1.1%**	**1.9%**	**0.3%**	**0.0%**	**1.5%**

Source: Table 4 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers for presentation in the table but calculations were based on actual numbers from data responses. A&N and Somerset did not provide a response to the Commission’s data request; moreover, Hagerstown, PE/AP, Thurmont and Williamsport are winter peaking service territories, while Berlin, BGE, Choptank, DPL, Easton, Pepco and SMECO are summer peaking service territories.

Table A-5(d): Maryland Peak Demand Forecast (Gross of DSM Programs; MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE/AP	Pepco	SMECO	Thurmont	Williams -port	Total
2009	10	7,345	229	912	67	64	1,535	3,656	812	20	5	**14,653**
2010	10	7,373	231	919	68	62	1,552	3,690	835	20	5	**14,764**
2011	10	7,531	237	950	70	60	1,575	3,751	853	20	5	**15,061**
2012	10	7,727	243	985	71	60	1,601	3,809	871	20	5	**15,401**
2013	10	7,868	249	1,009	72	60	1,622	3,865	889	20	5	**15,669**
2014	10	8,015	257	1,029	74	61	1,639	3,906	905	20	5	**15,921**
2015	11	8,144	263	1,046	75	61	1,663	3,946	923	20	5	**16,154**
2016	11	8,271	267	1,063	76	61	1,684	3,980	940	20	5	**16,377**
2017	11	8,395	272	1,082	78	61	1,706	4,022	956	20	5	**16,606**
2018	11	8,518	278	1,100	79	61	1,725	4,063	974	20	5	**16,834**
2019	11	8,640	283	1,121	80	62	1,746	4,109	990	20	5	**17,067**
2020	11	8,761	288	1,141	82	62	1,762	4,155	1,007	20	5	**17,293**
2021	11	8,883	293	1,162	83	62	1,782	4,195	1,024	20	5	**17,519**
2022	12	9,008	298	1,181	84	62	1,802	4,235	1,040	20	5	**17,747**
2023	12	9,134	302	1,201	86	62	1,824	4,276	1,056	20	5	**17,977**
Change (2009-2023)	**2**	**1,789**	**73**	**289**	**19**	**-2**	**289**	**620**	**244**	**1**	**0**	**3,324**
Percent Change	**21.6%**	**24.4%**	**31.9%**	**31.7%**	**28.1%**	**-2.5%**	**18.8%**	**17.0%**	**30.1%**	**4.3%**	**0.0%**	**22.7%**
Annual Growth Rate	**1.4%**	**1.6%**	**2.0%**	**2.0%**	**1.8%**	**-0.2%**	**1.2%**	**1.1%**	**1.9%**	**0.3%**	**0.0%**	**1.5%**

Source: Table 4 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers for presentation in the table but calculations were based on actual numbers from data responses. A&N and Somerset did not provide a response to the Commission's data request; moreover, Hagerstown, PE/AP, Thurmont and Williamsport are winter peaking service territories, while Berlin, BGE, Choptank, DPL, Easton, Pepco and SMECO are summer peaking service territories.

Table A-6(a): System-Wide Energy Sales Forecast (Net of DSM Programs; GWh)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE/AP	Pepco	SMECO	Thurmont	Williams-port	Total
2009	39	31,601	947	12,898	289	340	13,702	26,923	3,456	83	19	**90,297**
2010	39	32,115	964	12,884	295	330	13,928	26,877	3,569	83	19	**91,103**
2011	40	32,552	983	13,066	300	299	14,161	27,031	3,646	84	19	**92,182**
2012	40	33,059	1,011	13,330	306	300	14,487	27,289	3,713	84	19	**93,639**
2013	41	33,443	1,035	13,526	312	302	14,666	27,407	3,773	84	19	**94,607**
2014	41	33,810	1,058	13,758	318	303	14,899	27,532	3,826	84	19	**95,649**
2015	42	34,130	1,084	13,932	324	305	15,127	27,625	3,874	85	19	**96,547**
2016	43	34,579	1,108	14,170	329	308	15,423	27,879	3,921	85	19	**97,863**
2017	43	34,996	1,133	14,427	335	311	15,747	28,183	3,966	85	19	**99,244**
2018	44	35,438	1,159	14,668	341	314	16,056	28,487	4,010	86	19	**100,622**
2019	45	35,901	1,185	14,959	347	317	16,355	28,822	4,047	86	19	**102,082**
2020	45	36,410	1,209	15,231	353	320	16,633	29,161	4,088	86	19	**103,556**
2021	46	36,903	1,234	15,513	358	323	16,931	29,453	4,131	86	19	**104,997**
2022	47	37,431	1,258	15,773	364	326	17,260	29,746	4,175	87	19	**106,484**
2023	47	37,952	1,281	16,055	370	330	17,592	30,042	4,209	87	19	**107,984**
Change (2009-2023)	**8**	**6,351**	**334**	**3,156**	**81**	**-10**	**3,890**	**3,120**	**753**	**4**	**0**	**17,687**
Percent Change	**21.4%**	**20.1%**	**35.3%**	**24.5%**	**28.1%**	**-3.1%**	**28.4%**	**11.6%**	**21.8%**	**4.3%**	**0.0%**	**19.6%**
Annual Growth Rate	**1.4%**	**1.3%**	**2.2%**	**1.6%**	**1.8%**	**-0.2%**	**1.8%**	**0.8%**	**1.4%**	**0.3%**	**0.0%**	**1.3%**

Source: Table 5 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers for presentation in the table but calculations were based on actual numbers from data responses. A&N and Somerset did not provide a response to the Commission's data request.

Table A-6(b): Maryland Energy Sales Forecast (Net of DSM Programs; GWh)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE/AP	Pepco	SMECO	Thurmont	Williamsport	Total
2009	39	31,601	947	4,306	289	340	7,232	15,322	3,456	83	19	**63,634**
2010	39	32,115	964	4,333	295	330	7,321	15,178	3,569	83	19	**64,246**
2011	40	32,552	983	4,416	300	299	7,379	15,090	3,646	84	19	**64,808**
2012	40	33,059	1,011	4,533	306	300	7,505	15,189	3,713	84	19	**65,760**
2013	41	33,443	1,035	4,598	312	302	7,575	15,225	3,773	84	19	**66,406**
2014	41	33,810	1,058	4,651	318	303	7,650	15,219	3,826	84	19	**66,981**
2015	42	34,130	1,084	4,681	324	305	7,725	15,188	3,874	85	19	**67,457**
2016	43	34,579	1,108	4,765	329	308	7,863	15,333	3,921	85	19	**68,352**
2017	43	34,996	1,133	4,855	335	311	8,024	15,506	3,966	85	19	**69,272**
2018	44	35,438	1,159	4,939	341	314	8,173	15,679	4,010	86	19	**70,203**
2019	45	35,901	1,185	5,042	347	317	8,315	15,870	4,047	86	19	**71,174**
2020	45	36,410	1,209	5,137	353	320	8,447	16,063	4,088	86	19	**72,178**
2021	46	36,903	1,234	5,236	358	323	8,591	16,230	4,131	86	19	**73,157**
2022	47	37,431	1,258	5,327	364	326	8,757	16,397	4,175	87	19	**74,187**
2023	47	37,952	1,281	5,426	370	330	8,927	16,566	4,209	87	19	**75,214**
Change (2009-2023)	**8**	**6,351**	**334**	**1,121**	**81**	**-10**	**1,696**	**1,243**	**753**	**4**	**0**	**11,580**
Percent Change	**21.4%**	**20.1%**	**35.3%**	**26.0%**	**28.1%**	**-3.1%**	**23.4%**	**8.1%**	**21.8%**	**4.3%**	**0.0%**	**18.2%**
Annual Growth Rate	**1.4%**	**1.3%**	**2.2%**	**1.7%**	**1.8%**	**-0.2%**	**1.5%**	**0.6%**	**1.4%**	**0.3%**	**0.0%**	**1.2%**

Source: Table 5 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers for presentation in the table but calculations were based on actual numbers from data responses. A&N and Somerset did not provide a response to the Commission’s data request.

Table A-7: Licensed Electricity Suppliers and Brokers and Natural Gas Suppliers and Brokers (As of 12/31/2009)

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
A Better Choice Energy Services		IR-1697		IR-1698
Acclaim Energy, Ltd.		IR-1726		IR-1728
Affiliated Power Purchasers, Inc.		IR-279		
Allegheny Power Purchasers, Inc.	IR-229		IR-229	
Alternative Energy Sales, LLC		IR-1515		
Amerex Brokers, LLC		IR-1513		IR-1512
America PowerNet Management	IR-604			
AOBA Alliance, Inc.		IR-267		IR-375
API, INK		IR-1399		
ARS International, Inc.		IR-1181		
Association & Agency Consortium for Energy		IR-268		
Avalon Energy Services		IR-1693		IR-1743
BGE Home Products and Services d/b/a BGE Commercial Building Systems	IR-228		IR-311	
Blue Star Energy Services	IR-757			
BOC Energy Services	IR-753			
Bollinger Energy Corporation		IR-265	IR-322	
BP Energy Company			IR-676	
BTU Energy		IR-864		
Chesapeake Energy Services, Inc.		IR-1638		
Choice Energy Services		IR-682		
Clean Currents, LLC		IR-980		
Co-eXprise, Inc.	IR-879		IR-879	
Colonial Energy, Inc.			IR-606	
Commerce Energy, Inc.	IR-639		IR-737	

Table A-7: Licensed Electric Suppliers and Brokers and Natural Gas Suppliers and Brokers (As of 12/31/2009) Continued

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Compass Energy Services			IR-652	
Competitive Energy Services, MD	IR-895		IR-895	
ConocoPhillips Company			IR-1359	
Consolidation Edison Solutions	IR-603			
Constellation Energy Projects & Services Group	IR-239			
Constellation New Energy, Inc.	IR-500	IR-500	IR-522	IR-522
Constellation New Energy – Gas Division, LLC			IR-655	
Consumer Energy Solutions, Inc.			IR-1210	
CQI Associates, LLC		IR-575		
Creative Energy Options		IR-1528		
Cypress Natural Gas			IR-674	
DD&J LLC		IR-1560		
Delta Energy, LLC			IR-645	
DIBCO		IR-1207		
Direct Energy Services	IR-719		IR-791	
Dominion Retail, Inc.	IR-252		IR-345	
Downes Associates, Inc.		IR-523		
DTE Energy Trading, Inc.	IR-686			
Eastern Shore of MD Educational Consortium Energy Trust d/b/a ESMEC Energy Trust		IR-342		
EGP Energy Solutions		IR-1363		IR-1430
Electric Advisors, Inc.		IR-1183		IR-1523
Energy Advisory Service, LLC		IR-1486		IR-1485
Energy Options, LLC		IR-568		
Energy Services Management, LLC d/b/a Maryland Energy Consortium		IR-236		IR-312

Table A-7: Licensed Electric Suppliers and Brokers and Natural Gas Suppliers and Brokers (As of 12/31/2009) Continued

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Energy Trust, LLC		IR-1682		IR-1681
EnergyWindow, Inc.		IR-274		
Enron Energy Marketing Corp.			IR-370	
Enspire Energy			IR-814	
Essential.com, Inc.	IR-259			
FirstEnergy Solutions Corp.	IR-225			
Gateway Energy Services	IR-340		IR-334	
GDF Suez Energy Resources	IR-605			
Gexa Energy	IR-966			
Glacial Energy, Inc.	IR-888			
Goldstar Energy Group, Inc.		IR-1370		IR-1381
Good Energy, LP		IR-1592		
Hess Corporation	IR-219		IR-323	
Horizon Power & Light	IR-704			
Houston Energy Services Company, LLC.			IR-403	
Hudson Energy Services	IR-1114		IR-1120	
I.C. Thomasson Associates, Inc.		IR-1445		IR-1446
Integrys Energy Services	IR-951			
Knights of the Roundtable, Inc. d/b/a/ America Approved.com		IR-1664		
Liberty Power Corporation	IR-607			
Liberty Power, DE	IR-962			
Liberty Power Holdings	IR-957			
Liberty Power, Maryland	IR-793			
Long Distance Consultants, LLC		IR-1455		
Marathon Oil Company			IR-364	

Table A-7: Licensed Electric Suppliers and Brokers and Natural Gas Suppliers and Brokers (As of 12/31/2009) Continued

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Market Direct d/b/a MD Energy		IR-614		
MeadWestvaco Energy Services, LLC	IR-669			
Metromedia Energy, Inc.			IR-355	
Metromedia Power, Inc.	IR-867			
MidAmerican Energy Co.	IR-798			
Mid-Atlantic Aggregation Group Independent Consortium, LLC		IR-234		IR-234
Mid-Atlantic Renewables	IR-856			
Mitchell Energy Management Services		IR-1371		
Mona Building Technologies, LLC		IR-257		
MRDB Holdings	IR-930		IR-1000	
MxEnergy.com, Inc.			IR-327	
National Energy Consortium		IR-928		IR-928
National Utility Service, Inc.		IR-1410		IR-1400
Natures Current		IR-1352		IR-1436
New Power Company IBM Global Services	IR-336			
Northeast Energy Partners		IR-1649		
NOVEC Energy Solutions			IR-338	
Pepco Energy Services, Inc. d/b/a Conectiv Energy Services	IR-316		IR-316	
Pivotal Utility, Inc.			IR-376	
Platinum Advertising II LLC		IR-1673		IR-1668
Power Brokers, LP		IR-1610		IR-1669
Power Management		IR-1670		
PPL EnergyPlus, LLC	IR-230		IR-335	
Premier Energy Group	IR-942		IR-943	
Premier Power Solutions		IR-894		IR-894

Table A-7: Licensed Electric Suppliers and Brokers and Natural Gas Suppliers and Brokers (As of 12/31/2009) Continued

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
QVINTA, Inc.		IR-557		IR-530
Richards Energy Group, Inc.		IR-818		
Reliable Power Alternatives Corp.		IR-1719		
Reliant Energy Solutions East, LLC	IR-525			
Respond Power				IR-1440
Satori Enterprises, Inc.		IR-1499		
Sempra Energy Solutions	IR-442		IR-464	
Shell Energy, North America	IR-1357		IR-1358	
Smart Choice Energy Services		IR-1611		IR-1612
SmartEnergy.com, Inc.	IR-270			
South Jersey Energy Co.	IR-740			
South River Consulting		IR-863		
Sprague Energy Corp.				IR-339
Spark Energy	IR-979			
Spark Energy Gas			IR-613	
Stand Energy Corp.			IR-632	
Statoil Natural Gas, LLC			IR-561	
Strategic Energy, LLC	IR-437			
Summit Energy Services		IR-1396		
Texas Energy Options, Inc.		IR-1452		
TFS Energy Solutions d/b/a Tradition Energy		IR-918		IR-982
The Legacy Energy Group		IR-1692		IR-1691
Tiger Natural Gas			IR-351	
UGI Energy Services, Inc.	IR-237		IR-237	

Table A-7: Licensed Electric Suppliers and Brokers and Natural Gas Suppliers and Brokers (As of 12/31/2009) Continued

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Usource, LLC		IR-1160		
Utilitech, Inc.	IR-915		IR-915	
Virginia Power Energy Mktg. d/b/a Dominion Sales & Marketing, Inc.			IR-689	
Washington Gas Energy Services, Inc.	IR-227		IR-324	
World Energy Solutions, Inc.		IR-619		IR-953

The Table below lists the electricity and natural gas suppliers by license type. The license type indicates what services a supplier may offer in Maryland. The table below only indicates the license type and doesn't imply that all suppliers are offering services.

Electric Broker Only	32
Electric Supplier Only	27
Gas Broker Only	2
Gas Supplier Only	21
Electric Broker & Gas Broker	24
Electric Broker & Gas Supplier	1
Electric Supplier & Gas Supplier	19
Electric Supplier/Broker & Gas Supplier/Broker	1
Total Suppliers (incl. Brokers)	**127**

Table A-8: Transmission Enhancements by Service Area

Transmission Owner	#	Voltage (kV)	Length (miles)	No. of circuits	Start Date	End Date	In-Service Date	Purpose	From Location County	From Location Terminal	To Location County	To Location Terminal
Allegheny Power		138	0.1	2	2008	Suspd.	Unknown	GI		Kelso Gap (new)		Oak Park – Elk Garden
Allegheny Power		138	0.1	2	2009		2009	GI		Savage Mountain		Garrett – Carlos Junction
Allegheny Power		230	3.2	1	2009		2010	BTR		Doubs		Eastalco (Section 205)
Allegheny Power		230	3.7	1	2009		2010	BTR		Doubs		Eastalco (Section 205)
Allegheny Power		138	0.1	2	2011		2012	DA		Altamont (new)		Albright – Mt Zion
Allegheny Power		138	0.1	2	2011		2012	DA		McDade		Halfway – Paramont No. 1
Allegheny Power		230	8	2	2008		2009	BTR		Doubs		Dickerson
Allegheny Power		230	0.1	1	2008		2009	BTR		Frederick "A"		Monacy
Allegheny Power		230	2.1	2	2009		2010	DA		Urbana		Lime Kiln – Montgomery
Allegheny Power		138	8	1	2012		2013	DA		Emmitsburg		Catoctin
Allegheny Power		138	4.8 in MD	1	2010		2011	BTR		Marlowe		Halfway
Allegheny Power		230	0.6	2	2010		2011	DA		Ridgeville		Mt. Airy – Damascus
Allegheny Power		230	0.1	2	2010		2011	DA		South Frederick		Monacy Lime Kiln
Allegheny Power		230	0.1	2	2011		2011	DA		Jefferson No. 1		Doubs – Monacy
Allegheny Power		500	34.0	2	2011		2012	DA		Bedington		Kemptown (new)
Allegheny Power		138	0.1	2	2011		2012	DA		Fairplay		Marlowe – Boonsboro
Allegheny Power		230	7.8	1	2017		2017	BTR		Montgomery		Bucklodge
BGE		115	7.4	2	1/04	3/09		BTR, DA	Balt City	Westport	Balt City	Orchard (New)
BGE		115	3.3	1	1/07	2/2009		DA	Balt Co.	Northwest	Balt Co.	Finksburg
BGE		115	3.0	2	6/07	5/11		DA	Balt City	Westport	Balt City	Wilkens (new)
BGE		230	8.6	1	1/09	6/12		BTR	Harford	Conastone	Harford	Graceton
BGE		230	5.9	1	1/07	6/12		BTR	Baltimore	Raphael	Harford	Bagley
Choptank		25	2.9	1					Denton	Oil City	Denton	
DPL		69	5.32	1	9/04	12/08		DA	Grasonville		Stevensville	
DPL		69	11.13	1	9/07	12/09		DA	Easton		Bozman	
DPL		69	2.5	1	1/09	5/10		BTR	Berlin		Worcester	
DPL		69	18.41	1	1/08	5/10		BTR	Trappe		Todd	

Table A-8: Transmission Enhancements by Service Area (Continued)

									From Location		To Location	
Transmission Owner	#	Voltage (kV)	Length (miles)	No. of circuits	Start Date	End Date	In-Service Date	Purpose	County	Terminal	County	Terminal
DPL		138	12.98	1	1/10	5/12		BTR	Easton		Wye Mills	
DPL		69	12	1	1/09	5/12		DA	McCleans		Lynch	
DPL		69	12	1	1/09	5/12		DA	McCleans		Chestertown	
DPL		69	4.42	1	1/12	5/13		BTR	Vienna		Sharptown	
DPL		69	2.61	1	1/12	5/13		BTR	Ocean Bay		Maridel	
DPL		138	13.73	1	9/11	5/14		BTR	Vienna		Nelson	
DPL		138	24	1	1/11	5/14		BTR	Church		Wye Mills	
DPL		69	2.61	1	1/12	5/13		BTR	Ocean Bay		Maridel	
DPL		500	43	1	1/09	5/13		BTR	Calvert		Vienna	
DPL		230	18.7	1	1/10	5/13		BTR	Vienna		Loretto	
DPL		230	9.51	1	1/10	5/13		BTR	Loretto		Piney Grove	
DPL		500	35	1	1/09	5/13		BTR	Vienna		Indian River	
PEPCO		230	Bus Upgrade	1	1/09	5/10		BTR		Burtonsville		Sandy Springs
PEPCO		230	10.7	2	1/09	5/11		BTR		Dickerson		Quince Orchard
PEPCO		230	5.34	2	1/09	12/11		BTR		Ritchie		Benning
PEPCO		230	6.42	4	1/09	5/12		BTR		Burches Hill		Palmers Cornor
PEPCO		230	10.13	1	1/13	5/13		BTR		Dickerson		Quince Orchard
PEPCO		500	33	1	1/10	5/13		BTR		Possum Point		Burches Hill
PEPCO		500	19	1	1/10	5/13		BTR		Burches Hill		Chalk Point
PEPCO		500	20	1	1/10	5/13		BTR		Chalk Point		Calvert Cliffs

Purpose Codes:
BTR – Baseline transmission reliability
GI – Accommodate for generator interconnection
DA – Distribution Adequacy
TCA – Transmission Customer Adequacy
OTH – Other
AT – Asset Transfer from Government
RLC – Relocation
COR – Contingency Overload and/or Reliability

Table A-9: Renewable Projects Providing Capacity and Energy to Maryland Customers

Company	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)	2007 Net Generation (MWh)
A&N	N/A	N/A	N/A	N/A	N/A	N/A
Allegheny Power (PE)	None	None	None	None	None	None
Berlin	None	None	None	None	None	None
BGE	Alternative Energy Associates (AEA)/Brighton Dam	Laurel, MD	Yes	WAT	N/A	507
BGE	BRESCO (Baltimore Refuse Energy Systems Co.)	Baltimore, MD	Yes	MSW	57	321,177
Choptank	Worcester County Renewable Energy LLC	Worcester County Central Landfill	N/A	Methane Gas	1	NA
DPL	None	None	None	None	None	None
Easton	None	None	None	None	None	None
Hagerstown	none	None	None	None	None	None
PEPCO	Prince George's County Brown Station Landfill	Upper Marlboro, MD	Yes	Methane Gas	0	9,806
PEPCO	Prince George's County Detention Center	Upper Marlboro, MD	Yes	Methane Gas	0	6,149
SMECO	None	None	None	None	None	None
Somerset	N/A	N/A	N/A	N/A	N/A	N/A
Thurmont	None	None	None	None	None	None
Williamsport	None	None	None	None	None	None

Note: A&N and Somerset did not provide a response to the Commission's data request.

Table A-10: Comparison of Residential Demand Response Programs in Maryland

Issue	BGE	Pepco	Delmarva	SMECO
Total Number of Res. Customers Total Eligible Res. Customers Total Expected to Participate	approx. 1.1 million 900,000 450,000 (50%)	approx. 471,000 396,000 166,000 (42%)	approx. 171,000 91,130 54,000 (59%)	approx. 132,000 approx. 112,000 37,000 (33%)
Benefit to Cost Ratio	7.0/1.0 B/C ratio	3.1 TRC/All Ratepayers Test Only	2.9 TRC/All Ratepayers Test Only	2.13 non-traditional B/C calculation
Net Bill Impact/Non-Participants	Initial average Bill decrease $0.04 per Month - further Bill decreases thereafter	Initial average Bill decrease $0.38 per Month - further Bill decreases thereafter	Average Bill increases $0.02 per Month in 2011 Bill decreases after 2011	Initial average Bill increases $0.07 per Month in 2008 Bill decreases thereafter
Net Bill Impact/Participants	Initial average Bill decreases $10.46 per month - additional Bill decreases thereafter	Initial average Bill decrease $5.18 per month - additional Bill decreases thereafter	Initial average Bill decreases $4.99 per month	Initial average Bill decreases $3.80 per month -additional Bill decreases thereafter
Maximum Surcharge	$2.35 / Month	$0.81 / month	$0.58 / month	$2.62 / month
Cost/Device Thermostat/Switch	$276 Average per device (two-way Communication)	$300 Average per device (two-way communications)	$300 Average per device (two-way communications)	NA -- Bundled contract w/Comverge (two-way communication)
Utility Incentives	Tiered Structure as Per PSC Letter Order of 12/27/07	Tiered Structure as Per PSC Letter Order of 4/18/08	Tiered Structure as Per PSC Letter Order of 4/18/08	None Requested
Load Reduction/Device	1.38 kW	1.23 kW	1.23 kW	1.25 kW
Estimated Capacity Savings	605 MW	206 MW	67 MW	50 MW
Estimated Direct Energy Savings	$42 million 15-year NPV	$18.3 million 15-year NPV	$5.7 million 15-year NPV	$9 million 10-year NPV*
Net Savings	$965 million 15-year NPV	$225 million 15-year NPV	$45 million 15-year NPV	$24 million 10-year NPV*
Proposed Customer Incentives	$50/$75/$100 for cycling options 50%/75%/100%	$40/$60/$80 for cycling options 50%/75%/100%	$40/$60/$80 for cycling options 50%/75%/100%	$25 for Direct Load Control Switch $50 for Smart Thermostat

* SMECO's contract with Comverge is for 10 years.

Table A-11: Power Plants in the PJM Process for New Electric Generating Stations in Maryland (As of December 31, 2008)

Electric Company Service Territory	Status within PJM Queue	Ownership (%)	Plant Capacity (MW)	Fuel Type	Potential Use	Projected In-Service Date
Delmarva	T144: Pocomoke (Active)	0	10	Biomass	Merchant Generation (20 MW Energy)	2010 Q1
Delmarva	U3-004: Cecil (Active)	0	0	Methane	Merchant Generation (2 MW Energy)	2009 Q3
Delmarva	V2-028: Vienna (Active)	0	2.28	Solar	Merchant Generation (6 MW Energy)	2010 Q4
SMECO	CPV St. Charles	0	640	Natural Gas	Natural Gas	2012
PE	Suspended	0	640	Natural Gas	Capacity & Energy	2010 Q3
PE	Suspended	0	100	Wind	Energy Only	2010 Q4
PE	Suspended	0	40	Wind	Energy Only	2010 Q1
PE	Suspended	0	8	Wind	Capacity Only	2010 Q3
PE	Suspended	0	20	Wind	Capacity Only	2010 Q3
PE	Under Study	0	70	Wind	Capacity & Energy	2009 Q4
PE	Under Study	0	8	Coal	Energy Only	2009 Q3
PE	Under Study	0	30	Wind	Capacity & Energy	2010 Q4
PE	Under Study	0	2	Methane	Capacity & Energy	2009 Q4
PE	Under Study	0	60	Wind	Capacity & Energy	2010 Q4
PE	Under Study	0	50	Wind	Capacity & Energy	2010 Q3
PE	Under Study	0	200	Wind	Capacity & Energy (In PA-trans in MD)	2010 Q4
PE	Under Study	0	4	Coal	Energy Only	2008 Q3
PE	Under Study	0	14	Hydro	Capacity & Energy	2011 Q3
PEPCO	R-17 Kelson Ridge (Active)	0	640	Gas	Merchant Generation	2012 Q4
PEPCO	S-17 Talbert (Active)	0	225	Gas	Merchant Generation	2010 Q4
PEPCO	T-133 Chalk Pt.-Bowie (Active)	0	225	Gas	Merchant Generation	2011 Q2
PEPCO	T-134 Chalk Pt.-Bowie (Active)	0	325	Gas	Merchant Generation	2012 Q2
PEPCO	V2-37 Whiteoak (Active)	0	4.5	Gas	Merchant Generation	2010 Q2
PEPCO	V3-1 Morgantown-Oak Grove (Active)	0	750	Gas	Merchant Generation	2012 Q2

Source: Table 6 in Company data responses to the Commission's 2009 data request for the Ten-Year Plan.