PUBLIC SERVICE COMMISSION OF MARYLAND

TEN-YEAR PLAN (2011 – 2020) OF ELECTRIC COMPANIES IN MARYLAND

Prepared for the
Maryland Department of Natural Resources
In compliance with Section 7-201
of the Maryland Public Utilities Article
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State of Maryland
Public Service Commission

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LIST OF ACRONYMS AND DEFINITIONS USED

ACP	Alternative Compliance Penalty
AMI	Advanced Metering Infrastructure
ARR	Auction Revenue Right
ARRA	American Recovery and Reinvestment Act of 2009
BGE	Baltimore Gas and Electric Company
BRA	Base Residual Auction
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CIS	Customer Information System
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CSP	Curtailment Service Provider
DLC	Direct Load Control
DOE	United States Department of Energy
DPL	Delmarva Power & Light Company
DR	Demand Response or Demand Resource
DSM	Demand-Side Management
DY	Delivery Year
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EFORd	Equivalent Demand Forced Outage Rate
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISA	Energy Independence and Security Act of 2007
EISPC	Eastern Interconnection State Planning Council
ELRP	Economic Load Response Program
EMAAC	Eastern Mid-Atlantic Area Council
EMS	Energy Management System
EM&V	Evaluation, Measurement, and Verification
EPA	United States Environmental Protection Agency
ETR	Estimated Time of Restoration
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
GATS	Generation Attributes Tracking System
GIS	Geographic Information System
GW/GWh	Gigawatt/Gigawatt-hours
HVAC	Heating, Ventilation, and Air Conditioning
HVCS	High Volume Call Service
HVDC	High Voltage Direct Current
IOU	Investor-Owned Utility
IRM	Installed Reserve Margin
ISAC	Independent State Agency Committee
ISO	Independent System Operator

IVR	Interactive Voice Response
kV	Kilovolt
kW/kWh	Kilowatt/Kilowatt-hours
LDA	Load Deliverability Area
LMP	Locational Marginal Price
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MADRI	Mid-Atlantic Distributed Resources Initiative
MAPP	Mid-Atlantic Power Pathway
MDE	Maryland Department of the Environment
MDS	Mobile Dispatch System
MEA	Maryland Energy Administration
MW/MWh	Megawatt/Megawatt-hours
NERC	North American Electric Reliability Council
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff (PJM)
OMS	Outage Management System
OPC	Office of People's Counsel (Maryland)
OPSI	Organization of PJM States, Inc.
PATH	Potomac-Appalachian Transmission Highline
PE	The Potomac Edison Company
Pepco	Potomac Electric Power Company
PJM	PJM Interconnection, LLC (Pennsylvania-Jersey-Maryland)
PJM-EIS	PJM – Environmental Information Services, Inc
PSC/ MD PSC	Maryland Public Service Commission
PTR	Peak-Time Rebate
PUA	Public Utilities Article, *Annotated Code of Maryland*
REC	Renewable Energy Credit
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model (PJM)
RPS	Renewable Energy Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEIF	Maryland Strategic Energy Investment Fund
SGIG	Smart Grid Investment Grant
SMECO	Southern Maryland Electric Cooperative, Inc.
SOS	Standard Offer Service
SWMAAC	Southwest Mid-Atlantic Area Council
TEAC	Transmission Expansion Advisory Committee (PJM)
TrAIL	Trans-Allegheny Interstate Line
WMS	Work Management System

I. INTRODUCTION

Section 7-201 of the Public Utilities Article, *Annotated Code of Maryland* ("PUA"), requires the Maryland Public Service Commission ("Commission" or "PSC" or "MD PSC") to forward a Ten-Year Plan of Electric Companies in Maryland ("Ten-Year Plan") to the Secretary of Natural Resources on an annual basis. This report constitutes that effort for the 2011 – 2020 timeframe and, with exceptions as noted in the text, the referenced data and information is as it existed as of December 31, 2010. It is a compilation of information on long-range plans of Maryland electric utilities. This report also includes summaries of events that have affected or may affect the electric utility industry in Maryland in the near future.

A principal focus of the Commission is the reliability of Maryland's electricity supply, delivered at reasonable rates. Achieving reliability is a complex undertaking which requires consideration of factors affecting both supply and demand. To address these elements the Commission is taking action on several fronts: challenging wholesale power policies at the Federal Energy Regulatory Commission ("FERC"); working with the wholesale independent 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 overall 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 of energy efficiency, conservation, and demand response as part of Maryland's supply resources, and discusses the effort required to meet EmPower Maryland goals. Proposals to deploy advanced metering infrastructure also are discussed in this section. Because environmental issues continue to play an increasingly important role in energy decisions, **Section VI** discusses Maryland's involvement in the Regional Greenhouse Gas Initiative and other issues involving the impact of renewable generation growth. **Section VII** provides information on distribution reliability, the manner in which utilities have managed outages, and how utilities plan to meet load requirements.

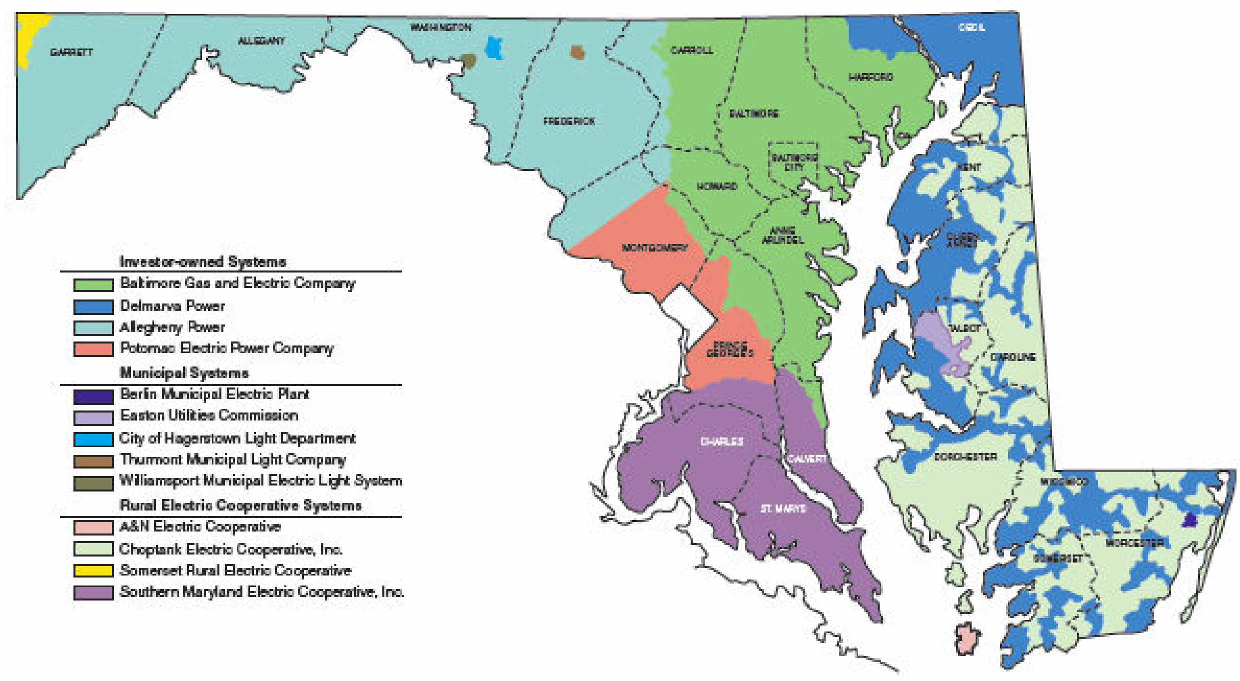
Beginning with **Section VIII**, we broaden our perspective and review Maryland's Electricity Market in general terms and its relation to Commission efforts that are currently underway or anticipated. **Section IX** discusses PJM Interconnection, LLC

[1] *See* EmPower Maryland Energy Efficiency Act of 2008, codified within MD. CODE ANN., PUB. UTIL. § 7-211 (2011) ("EmPower Maryland").

("PJM")[2] 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 U.S. 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 anticipated sales over the next 15 years.

Maryland is geographically divided into thirteen electric utility service territories. 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.[3] 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.[4]

<u>Map I.1: Maryland Utilities and their Service Territories in Maryland</u>



<u>Source</u>: *Cumulative Environmental Impact Report 15*, MD. DEP'T OF NATURAL RES., Figure 2-12, http://esm.versar.com/pprp/ceir15/Report_2_3.htm (last updated Feb. 25, 2010).

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[2] PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

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

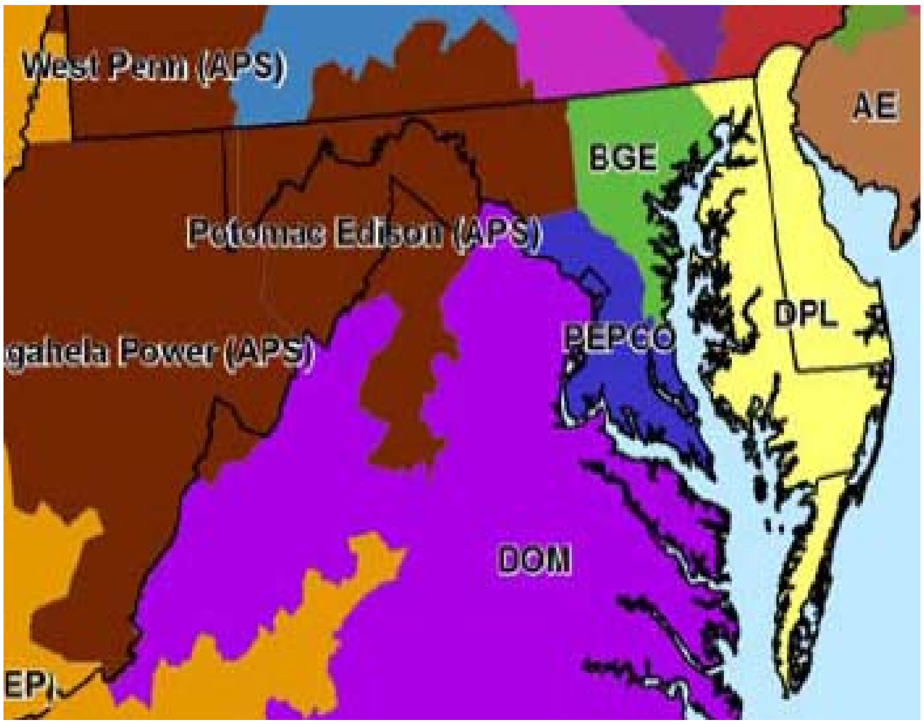
[4] The Potomac Edison Company no longer uses its "doing business name" of "Allegheny Power" and any references within the Ten-Year Plan to Allegheny Power should be read as referencing Potomac Edison.

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 routinely evaluates forecasts from individual utilities, as well as the PJM forecast, which provides separate estimates for the transmission zones shown in Figure II.A.1.

Figure II.A.1: PJM Maryland Forecast Zones



Source: *PJM Load Forecast Report*, PJM PLANNING (Jan. 2011), http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2011-pjm-load-report.ashx.

PJM sub-regions, known as zones, generally correspond with the IOU service territories. The PJM zones include adjacent municipal and rural electric cooperatives. The four IOUs operating in Maryland are Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), Delmarva Power & Light Company ("DPL" or "Delmarva"), and The Potomac Edison Company ("PE"). PJM zones for three of the four IOUs traverse state bounds and extend into other jurisdictions. Pepco, DPL, and PE 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 solely 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. PJM's load forecasts drive the need for generation, which impacts 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, projections 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, energy prices, and population. Non-economic variables can include weather normalized variables, monthly seasonal variables, ownership of appliances, and building codes.

B. PJM Zonal Forecast

PJM's 2011 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.[5] The 2011 Load Forecast Report concludes that the PJM region will, in aggregate, experience higher peak usage in the summer throughout the forecast period ending 2026.[6] Tables II.B.1 and II.B.2 present comparisons in expected growth for the four PJM zones containing Maryland.[7] The 2011 Load Forecast is compared to the 2009 and 2010 Load Forecasts 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 2011 Load Forecast shows significant reductions in both Summer and Winter peak demand growth rates from the previous year's Load Forecast. The PJM zones containing BGE, DPL, and Pepco experience their peak demands during the summer while the PJM region containing PE experiences peak demands in the winter.[8]

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

PJM Zone	2009-2019*	2010-2020**	2011-2021***
PE	1.5%	1.4%	1.0%
BGE	1.8%	1.8%	1.3%
DPL	2.1%	1.4%	1.1%
Pepco	1.2%	1.2%	1.0%

5 *PJM Load Analysis Subcommittee*, PJM, *available at*: http://www.pjm.com/committees-and-groups/subcommittees/las.aspx.

6 *PJM Load Forecast Report*, PJM, 37 (January 2011), *available at:* http://www.pjm.com/committees-and-groups/subcommittees/~/media/documents/reports/2011-pjm-load-report.ashx. The PJM RTO summer peak is forecasted to be 182,904 MW in 2026, a 15-year increase of 28,521 MW. *Id.*

7 For Maryland, the four PJM regions contain all four of the State's investor-owned utilities, the five municipal systems, and Maryland's four rural electric cooperatives. *Id.*

8 *Id.*

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

PJM Zone	2009-2019*	2010-2020**	2011-2021***
PE	1.3%	1.3%	1.0%
BGE	1.0%	1.1%	0.8%
DPL	1.5%	1.0%	0.8%
Pepco	1.1%	1.2%	1.0%

Sources: * PJM Load Forecast Report, January 2009, Tables B-1 and B-2.
** PJM Load Forecast Report, January 2010, Tables B-1 and B-2.
***PJM Load Forecast Report, January 2011, Tablets B-1 and B-2.

C. Maryland Company Forecasts

Maryland's electric utilities annually submit responses to Commission data requests that include forecasts of peak and annual energy demand. The forecast information provided by each company is summarized in the Appendices as Tables A-4(a) – (d) and Tables A-5(a) – (b). Data requests for the current Ten-Year Plan include responses that expand beyond a ten-year period – from 2011 through 2025. The prior year's submissions began and terminated one year earlier, that is, from 2010 through 2024. A comparison of the electric utility submissions for the first and last years of the forecast period is provided to indicate, on an aggregate basis, current expectations for peak usage in the State for electricity. The utility forecasts reflect: short-term recessionary impacts, the utilities' current expectations with regard 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: 2011, 2016, 2021, and 2024.[9] Additional analysis pertaining to 2011 and the period 2011 through 2021 also are 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. Actual peak demand in 2011 net of DSM programs compared to the 2010 forecasted peak demand net of DSM programs indicates that peak demand increased by 1.1%. Peak demand forecasts for this Ten-Year Plan period compared to the 2010 – 2019 Ten-Year Plan forecasted peak demand indicate that peak demands are estimated to increase by 0.7% in 2016, 0.7% in 2021, and 0.8% in 2024.[10]

9 Additional data for the 2011 to 2025 period can be located in Tables A-4 and A-5 of this Ten-Year Plan Appendix. Corresponding data considering the 2010 to 2024 time period can be located in last year's Ten-Year Plan Appendix Tables A-5 and A-6.

10 Increases are a comparison strictly to last year's submissions and 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	2010 - 2019 Ten-Year Plan	2011 - 2020 Ten-Year Plan	Change	%
2011	13,638	13,786	148	1.1
2016	13,812	13,914	102	0.7
2021	14,801	14,900	99	0.7
2024	15,381	15,511	130	0.8

Sources: *Ten-Year Plan (2010-2019) of Electric Companies in Maryland*, MD PSC, 6 (Aug. 2011), *available at*: http://webapp.psc.state.md.us/Intranet/Reports/2010-2019%20Ten%20Year%20Plan.pdf. *See* Appendix Table A-4(b).

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 increases in overall annual electricity sales in the State. During the timeframe examined, increases in energy usage trend upward[11] between 0.6% and 1.4% when compared to last year's electric utility submissions.

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

Year	2010 - 2019 Ten-Year Plan (GWh)	2011 - 2020 Ten-Year Plan (GWh)	Change	%
2011	63,651	64,012	361	0.6
2016	66,954	66,887	-67	-0.1
2021	71,111	72,056	945	1.3
2024	73,848	74,865	1,017	1.4

Sources: *Ten-Year Plan (2010-2019) of Electric Companies in Maryland*, MD PSC, 6 (Aug. 2011), *available at*: http://webapp.psc.state.md.us/Intranet/Reports/2010-2019%20Ten%20Year%20Plan.pdf. *See* Appendix Table A-5(b).

As reflected in Table II.C.1 and Table II.C.2, utility projections of peak demand and of annual energy sales are currently moving in similar directions: peak demand is increasing and annual energy sales are increasing when compared to utility estimates provided last year. Historically, peak demand and annual energy sales have moved in tandem.

Numerous changes have occurred or have been proposed to PJM demand response ("DR") programs recently. These changes include implementing a more accurate method of measuring and verifying the quantity of demand reductions provided

[11] Although the comparison of 2016 forecasted energy sales between the 2010 – 2019 TYP and the 2011 – 2020 TYP indicates a 0.1% reduction, utility data for the 2011 – 2020 TYP reflects an increase in forecasted State energy sales in the aggregate when compared to the 2010 – 2019 TYP forecast. *See* Appendix Table A-5(b).

and proposals to significantly expand both the time period and the seasons during which DR participants must reduce load. The uncertainty associated with such changes leads to less aggressive projections of future DR participation and DSM impacts.

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 electricity using high-voltage transmission lines, local generation must be maintained and is essential to keeping 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 2010, Maryland's net summer generating capacity was approximately 12,516 MW.[12] Maryland's peak demand forecast for 2011 with utility demand-side management and energy conservation measures is approximately 13,786 MW.[13] According to PJM's established margin for necessary reserves, an additional 2,137 MW[14] is required and would result in a cumulative estimated reliability requirement of 15,923 MW. Therefore, 3,407 MWs 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

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12 *See* Tables III.B.1 and III.B.3.

13 *See* Appendix Table A-4(b).

14 The example uses an installed reserve margin ("IRM") of 1.155 for 2010/2011, which is applicable for planning reserves on a 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 – considering demand forecasts, available unforced capacity from existing generation, and the probability that 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, 3, *available at*: http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-reserve-requirement-study.ashx.

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.

Within eastern PJM, the District of Columbia, Maryland, Delaware, New Jersey, and Virginia continue to be net importers of electricity. Maryland imported about 40 percent of its electricity in 2009.[15] On a percentage basis, Maryland was the fifth largest electric energy importer in the United States – surpassed by the District of Columbia, Delaware, and Virginia in the immediate PJM area.[16] 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 within the PJM region currently exporting more electricity in aggregate than consumed within each state are Illinois, Indiana, Pennsylvania, and West Virginia.[17]

<u>Table III.A.1: State Electricity Imports (Year 2009) (GWh)</u>

State	Retail Sales	Losses & Direct Use	Generation	Net Imports	Percent Retail Sales Imported
DC	12,199	785	35	(12,984)	106%
Delaware	11,258	1,298	4,842	(7,714)	69%
Idaho	22,754	2,635	13,100	(12,333)	54%
Virginia	108,462	8,338	70,082	(46,719)	43%
Maryland	62,589	5,924	43,775	(24,738)	40%
California	259,584	31,858	204,776	(84,137)	32%
New Jersey	75,780	5,630	68,811	(19,598)	26%
Massachusetts	54,359	3,216	38,967	(14,036)	26%
Tennessee	94,650	7,137	79,717	(22,070)	23%
Wisconsin	66,286	5,825	59,959	(12,153)	18%
Minnesota	64,004	6,891	52,492	(10,611)	17%
North Carolina	127,658	11,672	118,407	(20,922)	16%
Louisiana	78,670	24,670	90,994	(12,346)	16%
Ohio	146,300	11,550	136,090	(21,755)	15%
Georgia	130,766	15,814	128,698	(17,881)	14%
Florida	224,750	21,646	217,952	(28,444)	13%
Colorado	51,036	4,345	50,566	(4,815)	9%
Mississippi	46,049	5,563	48,701	(2,911)	6%
New York	140,034	3,026	133,151	(7,606)	5%
Alaska	6,270	770	6,702	(337)	5%
Kentucky	88,809	5,397	90,630	(3,576)	4%
Hawaii	10,126	1,166	11,011	(282)	3%
Michigan	98,121	10,076	101,203	(1,357)	1%
Texas	345,296	54,439	397,168	(2,456)	1%

<u>Source</u>: *State Electricity Profiles 2009*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 10, (April 15, 2011) *available at*: http://www.eia.gov/cneaf/electricity/st_profiles/sep2009.pdf.

15 *State Electricity Profiles 2009*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 10, (April 15, 2011) *available at*: http://www.eia.gov/cneaf/electricity/st_profiles/sep2009.pdf.
16 *Id.*
17 *Id.*

B. Maryland Generation Profile: Age and Fuel Characteristics

Most electric generating capacity in Maryland is provided by coal-fired power plants, which contribute approximately 39 percent of the summer peak capacity available in-State. The vast majority of the State's coal-fired generation capacity, approximately 70 percent, is provided by power plants thirty-one or more years old. Approximately 41 percent of all capacity in Maryland burns oil or gas as a fuel source, and the majority of these facilities are aging. Overall, approximately 67 percent of Maryland generating capacity has been in operation for over 30 years. As indicated in Table III.B.1, only about 16 percent of the State's summer generating capacity has been constructed in the past 20 years, and only about 7 percent has been constructed in the last 10 years.

Table III.B.1: Maryland Generating Capacity Profile (Year 2010)

	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	4886	39.04%	0.0%	16.7%	13.0%	70.3%
Oil & Gas	5126	40.96%	14.2%	21.0%	13.3%	51.5%
Nuclear	1705	13.62%	0.0%	0.0%	0.0%	100.0%
Hydroelectric	590	4.71%	0.0%	0.0%	0.0%	100.0%
Other & Renewables	209	1.67%	43.9%	25.9%	30.2%	0.0%
TOTAL	**12516**	**100.00%**	**6.5%**	**15.6%**	**11.0%**	**66.9%**

Source: *Report EIA-860: "GenY10" Excel*, U.S. ENERGY INFORMATION ADMINISTRATION, (Nov. 30, 2011), *available at*: http://www.eia.gov/cneaf/electricity/page/eia860.html.

In the past few years several older generating units in the eastern PJM region have requested deactivation. These older generating units are located in Delaware, Pennsylvania, New Jersey, Virginia, and the District of Columbia. These older generation units typically have operated only a limited number of hours each year recently and generate electricity at relatively high marginal costs. However, the units also may 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.[18] The following paragraphs summarize the pending deactivations of generating facilities in the PJM region; several official owner requests for retirement date back to 2007.

In 2007, owners of power plants requested deactivation of units at locations in D.C.: two Buzzard Point plants with a combined capacity of 240 MW; and two Benning site power plants, 550 MW. The reliability issues have been identified for all units and

[18] *Manual M-14D: Generator Operational Requirements, Revision: 17*, PJM (effective date Jan. 1, 2010), *available at*: http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

are expected to be resolved to meet the requested deactivation dates.[19] All the units are scheduled for deactivation on May 31, 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 345 MW; two Eddystone units (Pennsylvania), 588 MW; and two units at the Kearny (New Jersey) site, 250 MW. On May 31, 2011, one Cromby unit and one Eddystone unit were deactivated[20]; the remaining four units have requested deactivation dates between May of 2011 and June of 2012. Reliability impacts were identified with the Eddystone unit and with the Cromby unit. The requested deactivation date for the Eddystone unit has been delayed from May 31, 2011 to May 31, 2012, and the requested deactivation date for the Cromby unit has been delayed from May 31, 2011 to December 31, 2011. Additionally, a reliability analysis remains underway for both Kearny units.[21]

In 2010, owners of power plants requested deactivation of five units that remain pending: one Kearney unit with a capacity of 21 MW; a Cromby Diesel unit, 2.7 MW; the Ingenco Petersburg plant, 2.9 MW; an Indian River unit, 169.7 MW; and one Sporn unit, 440 MW. The reliability analysis remains underway for the Kearney unit, with a projected deactivation timeline reaching into May of 2015. The reliability analyses were completed for the other four units, and all issues are expected to be resolved to meet the requested deactivation dates.[22] Depending on the unit, deactivation is projected between May of 2011 and December of 2013.

In 2011, owners of power plants requested deactivation of nineteen units: two State Line units with a combined capacity of 515 MW; one Vineland unit, 23 MW; one Viking Energy unit, 16 MW; five Potomac River units, 482 MW; four Chesapeake units, 576 MW; one Yorktown unit, 159 MW; one Bergen unit, 21 MW; one Burlington unit, 21 MW; one National Park unit, 21 MW; one Mercer unit, 115 MW; and one Sewaren unit, 111 MW. The reliability analyses remain underway for the majority of the units, although results are available for both State Line units, the Vineland unit, the Viking Energy unit, and all five Potomac River units. The reliability issues identified in the completed analyses are expected to be resolved to meet the requested deactivation dates.[23] Depending on the unit, deactivation is projected between 2012 and 2015.

Several requests for deactivation were filed in the opening months of 2012. One noteworthy request is an application submitted on January 26, 2012 by FirstEnergy

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19 *Pending Deactivation Requests*, PJM PLANNING (Feb. 6, 2012), *available at*: http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.

20 *PJM Generator Deactivations*, PJM PLANNING (Jan. 10, 2012), *available at*: http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/generator-deactivations.ashx.

21 *Pending Deactivation Requests*, PJM PLANNING (Feb. 6, 2012), *available at*: http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.

22 *Id.*

23 *Id.*

(formerly Allegheny Power) that references two units located in this State; R. Paul Smith 3 has been in service for 64 years and represents a 28 MW capacity, while R. Paul Smith 4 has been in service for 43 years and represents a capacity of 87 MW. The reliability analysis is underway, and PJM has listed a projected deactivation date of September 1, 2012 for both R. Paul Smith units.[24]

The Maryland generating profile differs considerably from its capacity profile. Coal and nuclear facilities generate over 88 percent[25] of all electricity produced in Maryland, even though they represent little more than half of in-State capacity.[26] In contrast, oil and gas facilities, which tend to operate as mid-merit or peaking units that come on-line only when needed, generate less than 6 percent of the electricity produced by in-State resources, while representing approximately 41 percent of in-State capacity.[27] Table III.B.2 summarizes Maryland's in-State fuel-mix in MWh by generating sources for 2009. In 2009, Maryland plants produced 43,774,832 MWh of electricity.

Table III.B.2: Maryland Electric Power Generation Profile (Year 2009)

Source	**MWh**	**Share (%)**
Coal	24,162,345	55.2
Oil & Gas	2,366,927	5.4
Nuclear	14,550,119	33.2
Hydroelectric	1,888,769	4.3
Other & Renewables	806,671	1.9
Total	**43,774,832**	**100.0**

Source: *Maryland Electricity Profile*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 5, (April 15, 2011), *available at*: http://www.eia.gov/cneaf/electricity/st_profiles/maryland.html.

The total summer capacity of Maryland generators is approximately 12,516 MW,[28] of which approximately 80 percent of the in-State generation capacity is owned by two companies or their subsidiaries: Constellation Energy Group and GenOn Energy, Inc. ("GenOn"). Constellation Energy Group owns about 43 percent of this capacity, and GenOn owns about 37 percent.[29] Nearly two-thirds (65 percent) of the State's power plant capacity resides in one of four counties: Prince George's, 21 percent; Anne Arundel, 18 percent; Calvert, 14 percent; and Charles, 12 percent. Table III.B.3 lists Maryland generating units by owner, county, and capacity.

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24 *Id.*

25 *See* Table III.B.2. In 2009 coal facilities generated 55.2% of Maryland's electricity and nuclear facilities generated 33.2%, for a total representative of 88.4% of Maryland's electric power generation profile in 2009. *Id.*

26 *See* Table III.B.1. Coal facilities represented 39.04% of the in-State capacity in 2010 while nuclear facilities represented 13.62% of the capacity in 2010. Therefore, coal and nuclear facilities combined for 52.66% of Maryland's generating capacity profile in 2010. *Id.*

27 *Id.*

28 *See* Table III.B.3.

29 *Id.*

Table III.B.3: Generation by Owner, County, and Capacity (Year 2010)

Operator/Owner	Plant Name	County	Capacity Statistics (MW)		
			Name Plate	*Summer*	*Pct. Summer*
A & N Electric	Smith Island	Somerset	1.7	1.6	0.01%
AES Warrior Run	AES Warrior Run	Allegany	229	180	1.44%
Allegheny Energy	R Paul Smith	Washington	109.5	115	0.92%
American Sugar	Domino Sugar	Baltimore City	17.5	17.5	0.14%
Town of Berlin	Berlin	Worcester	9	9	0.07%
BP Piney & Deep Creek LLC	Deep Creek	Garrett	20	18	0.14%
Calpine Mid-Atlantic Generation LLC	Crisfield	Somerset	11.6	10.4	0.08%
Constellation	Calvert Cliffs	Calvert	1828.7	1705	42.55%
Constellation	Brandon Shores	Anne Arundel	1370	1273	
Constellation	C P Crane	Baltimore	415.8	399	
Constellation	Gould Street	Baltimore City	103.5	97	
Constellation	Herbert A Wagner	Anne Arundel	1058.5	975.9	
Constellation	Notch Cliff	Baltimore	144	116.7	
Constellation	Perryman	Harford	404.4	353.6	
Constellation	Philadelphia	Baltimore City	82.8	60.9	
Constellation	Riverside	Baltimore	257.2	228	
Constellation	Westport	Baltimore City	121.5	115.8	
Constellation Solar Maryland, LLC	McCormick & Co. Inc. at Belcamp	Hartford	1.4	1.4	0.01%
Covanta Montgomery, Inc.	Montgomery County Resource Recovery	Montgomery	67.8	54	0.43%
Criterion Power Partners LLC	Criterion Wind Project	Garrett	70	70	0.56%
Eastern Landfill Gas LLC	Eastern Landfill Gas LLC	Baltimore	3	3	0.02%
Easton Utilities Comm	Easton	Talbot	33.6	31.9	0.55%
Easton Utilities Comm	Easton 2	Talbot	38.8	37	
Energy Recovery Operations, Inc	Harford Waste to Energy Facility	Harford	1.2	1.1	0.01%
Exelon Power	Conowingo	Harford	506.8	572	4.57%
GenOn Chalk Point LLC	Chalk Point LLC	Prince Georges	2,647	2,347	37.30%
GenOn Mid-Atlantic LLC	Morgantown Generating Plant	Charles	1,548	1,477	
GenOn Mid-Atlantic LLC	Dickerson	Montgomery	930	844	
Industrial Power Generating Company LLC	Wicomico	Wicomico	5.4	5.4	0.04%
Maryland Environmental Service	Eastern Correctional Institute	Somerset	5.8	4.6	0.04%
NAEA Rock Springs LLC	NAEA Rock Springs LLC	Cecil	772.6	652	5.21%
NewPage Corporation	Luke Mill	Allegany	65	60	0.48%
NRG Vienna Operations Inc	Vienna Operations	Dorchester	183	170	1.36%
Panda-Brandywine LP	Panda Brandywine LP	Prince Georges	288.8	230	1.84%
Power Choice/Pepco Energy Serv	NIH Cogeneration Facility	Montgomery	22	21.2	0.17%
Prince George's County	Brown Station Road Plant I	Prince Georges	6.7	5.6	0.04%
RG Steel LLC	RG Steel Sparrows Point, LLC	Baltimore	120	152.3	1.22%
SCE Engineers	Montgomery County Oaks LFGE Plant	Montgomery	2.4	2.3	0.02%
Solo Cup Co	Solo Cup Co	Baltimore	11.2	11.2	0.09%
Trigen Inner Harbor East, LLC	Inner Harbor East Heating	Baltimore City	2.1	2.1	0.18%
Trigen-Cinergy Solutions College Park	UMCP CHP Plant	Prince Georges	27.4	20.8	
Wheelabrator Environmental Systems	Wheelabrator Baltimore Refuse	Baltimore City	64.5	61.3	0.49%
Worcester County Renewable Energy LLC	Worcester County Renewable Energy	Worcester	2	2	0.02%
			13,611.20	**12,515.60**	**100.00%**

Source: *Report EIA-860: "GenY10" Excel*, U.S. ENERGY INFORMATION ADMINISTRATION, (Nov. 30, 2011), *available at*: http://38.96.246.204/cneaf/electricity/page/eia860.html.

C. Potential Generation Additions in Maryland

Siting for central station generation in Maryland continues to be an important concern. There are reliability, environmental, and competitive issues that must be resolved when finding an appropriate location for a new generator. Generation is largely deregulated and currently the responsibility of independent power producers. 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 generation companies to secure potential new sites, long-term sales contracts, and the funding necessary to build new generation.

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 projects in the Atlantic Ocean, 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.

Although no significant generation has been constructed in Maryland within the past few years, the Commission has granted both CPCNs and approvals for construction for those who quality for CPCN exemptions for new generation. Furthermore, no units have been retired recently. The Commission currently has before it several applications for construction of new generation and transmission. When and if constructed, these projects will make available additional electricity for use in Maryland and the PJM region, and should ease congestion substantially.

In 2009, the Commission initiated a new proceeding (Case No. 9214) to consider proposals for new electric generation facilities in Maryland. On September 29, 2011, the Commission issued a Notice of Approval of Request for Proposals for New Generation to be issued by Maryland Electric Distribution Companies. Attached to that notice was a Request for Proposals inviting interested persons to submit proposals to the Commission to construct new generation facilities that would produce and sell electricity to Maryland's regulated electric distribution companies. Proposals were due to the Commission January 20, 2012. Additionally, the Commission set for comment whether new generation is needed to meet the long-term anticipated demand in Maryland for standard offer service and other electric supply and if so, the quantity of generation needed. A hearing on the comments was held January 31, 2012.

The status of Commission proceedings covering proposed new electric generator facilities in Maryland (projects ineligible for CPCN exemptions as discussed in Section III.D.) that were active cases in late 2009 through 2011, is as follows :

> CN9206: A CPCN application from Constellation Power Source Generation Inc. authorizing the modification of the C.P. Crane generating station for the use of sub-bituminous coal in Baltimore County. Testimony filed January 13, 2010. In-service June 9, 2010.
>
> CN9218: A CPCN application from UniStar, LLC authorizing the modification of the Calvert Cliffs Unit 3 nuclear project for ancillary equipment that will increase air emissions. In-service April 26, 2010.
>
> CN9199: A CPCN Application from Energy Answers International, Inc. to construct a 120 MW Generating Facility in Baltimore using processed waste for fuel. On December 29, 2011, Energy Answers filed a motion to toll its construction deadline contained in the CPCN.
>
> CN9229: A CPCN Application from Mirant for STAR, a processor for flyash at the Morgantown Power Plant in Charles County. In-service November 4, 2010.

In addition to the aforementioned CPCN applications, Maryland is experiencing an uptick in the amount of solar generation capacity both planned and already available to the State. Section VI.C. details the Commission's efforts to spur small-scale solar generator interconnection throughout Maryland. On the utility-scale, plans for new solar generation also began taking shape in 2011; Case Number 9272 was opened for the CPCN application of Maryland Solar LLC to construct a 20 MW solar photo-voltaic generating facility in Hagerstown, Maryland. The Commission granted approval on October 8, 2011 for construction of the Hagerstown facility in Order No. 84369. Other notable examples of planned new solar generation include the October 26, 2011 Commission approval for SMECO Solar LLC to construct a Type IV solar generator in Hughesville.[30] Additionally, on December 14, 2011, the Commission granted approval to Constellation Solar Holding, LLC to construct a solar photovoltaic generation project located at Mount St. Mary's University comprising two solar arrays with capacities of 1.25 MW and 250 kW, respectively.[31]

The number of projects for which a transmission interconnection request (capacity or energy) has been filed with PJM provides an indication of potential generation capacity additions in Maryland. Table III.C.1 lists the new generation projects located in Maryland for which a transmission interconnection request has been made to PJM and that are categorized as under study, under construction, providing partial service, or

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[30] The Commission granted approval of SMECO Solar LLC's application for an exemption of the CPCN requirement. Letter Order, Maillog No. 134380.

[31] The Commission granted approval of Constellation Solar Holding, LLC's application for an exemption of the CPCN requirement. Letter Order, Maillog No. 135780.

currently suspended. The Table demonstrates the diversity of projects being pursued throughout the State. The vast majority (about 89%) of proposed new generation capacity would be located within the Southern Maryland Electric Cooperative, Inc. ("SMECO") and Pepco service territories, and would use primarily natural gas or nuclear fuel. Additional generation capacity, especially from renewable sources, has been proposed for the DPL and PE service territories.

Table III.C.1: PJM Transmission Queue Active New Generating Capacity

Plant Capacity (MW) By Fuel					
Service Territory	**Natural Gas**	**Nuclear**	**Other & Renewable**	**Total**	**In-service Dates**
BGE	259	-	290	549	2012-2015
DPL	-	-	478	478	2009-2017
PE	-	-	259	259	2009-2013
PEPCO	8,520	-	28	8,548	2012-2017
SMECO	-	1,640	-	1,640	2017
TOTAL	3,060	-	205	11,474	2010-2017

Source: *See* Appendix Table A-9.

D. CPCN Exemptions for Generation

Pursuant to Public Utilities Article § 7-207.1, certain power generating stations are exempt from the requirement to obtain a CPCN, subject to Commission approval, prior to commencing construction of the generating station. These approvals are available to generating stations that are designed to provide on-site generated electricity and that meet the following qualifications:[32]

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.[33]

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[32] PUA § 1-101(s) 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.

[33] The Statute also provides for an exemption from the CPCN process for a generating station that does not exceed 25 MW 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. MD. CODE ANN., PUB. UTIL. § 7-207.1 (2011).

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 approval without obtaining a CPCN. The first is that the generating station must be land-based; therefore, any off-shore facility within State waters will be required to obtain a CPCN. The second qualification is that the Commission must provide an opportunity for public comment at a public hearing.

The Commission's PUA § 7-207.1- approved 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.[34] An emergency or back-up generator is the most common Type I generator. A Type II generator is synchronized 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.

In order to obtain approval to construct a generator under PUA § 7-207.1, 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 complying with other regulations or from obtaining all other necessary State and local permits, such as those required by the Air and Radiation Management Administration at the Maryland Department of the Environment ("MDE").

Table III.D.1 provides an overview of the number and capacity of generators that have applied for PUA § 7-207.1 approvals on an annual basis. The number of applications has generally been increasing over time, and these generators have a cumulative generation capacity of over 1,300 MW.

[34] PUA § 1-101(h) defines "Electric company," with certain exclusions, as a person who physically transmits or distributes electricity in the State to a retail electric customer.

Table III.D.1: Construction Approvals for CPCN Exempt Generation

Period Approved	Applications	No. of Units	Total (MW)
Calendar Year 2001	4	7	35.4
Calendar Year 2002	9	26	68.3
Calendar Year 2003	21	29	43.4
Calendar Year 2004	36	58	77.1
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	130	212.1
Calendar Year 2009	102	153	269.2
Calendar Year 2010	101	152	167.2
Calendar Year 2011	78	138	188.6
Total	**530**	**880**	**1314.4**
Pending	10	16	16.0
Total (Including Pending)	**540**	**896**	**1330.4**

Source: PSC database.
Note: 2011 data is current as of October 31, 2011. Each application may contain multiple generation units.

Table III.D.2 reflects that fossil fuel generators were 92.6% of the 896 generator units reported. These fossil fuel generators provided 1070.0 MW (80.4%) of the total 1330.4 MW of generating capacity reported. Oil remained the dominant fuel source for new generators. Oil-fired generators were 930.1 MW (69.9%) of the total generation reported. Wind-powered units provided 189.6 MW (14.3%) of total CPCN exempt capacity. Solar-powered units provided 44.7 MW (3.4%) of total CPCN exempt capacity.

Table III.D.2: Number and Capacity in MW of CPCN Exempt Generating Units by Energy Resource

Energy Resource		Total Approved	Percent of Total Approved
GENERATOR UNITS			
Fossil	**Oil**	790	88.2%
	Natural Gas	38	4.2%
	Propane	2	0.2%
Fossil Total		***830***	***92.6%***
Renewable	**Biomass**	1	0.1%
	Digester Gas	3	0.3%
	Landfill Gas	3	0.3%
	Solar	56	6.3%
	Wind	3	0.3%
Renewable Total		***66***	***7.4%***
Grand Total		**896**	**100.0%**
CAPACITY (MW)			
Fossil	**Oil**	930.1	69.9%
	Natural Gas	139.8	10.5%
	Propane	0.2	0.0%
Fossil Total		***1070.0***	***80.4%***
Renewable	**Biomass**	19.8	1.5%
	Digester Gas	3.2	0.2%
	Landfill Gas	3.1	0.2%
	Solar	44.7	3.4%
	Wind	189.6	14.3%
Renewable Total		***260.3***	***19.6%***
Grand Total		**1330.4**	**100.0%**

Source: PSC database.
Note: Data is current as of November 1, 2011.

IV. TRANSMISSION INFRASTRUCTURE: PJM, MARYLAND, AND NATIONAL

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, has led to higher energy and capacity costs in portions of Maryland and the surrounding states since local, but more expensive, generation resources had to be deployed to meet load. Adequate capacity and reliable supplies of electricity are continually monitored, managed, and, when necessary, supplemented with additional infrastructure.

B. Eastern Interconnection Planning Collaborative

During 2011, the Eastern Interconnection Planning Collaborative ("EIPC") completed the first phase of its work identifying a broad range of alternative futures to be analyzed by a production cost model. Eight futures were modeled under varying assumptions. The futures modeled were:

1. Business as Usual – This Future continues today's policies.
2. National Carbon Policy/National Implementation – This Future envisions a national Carbon Emission Mitigation policy to be fulfilled by constructing no/low carbon – emitting energy generation facilities in the most productive generation resource areas and building transmission to connect those generation facilities to customers in the Eastern Interconnection.
3. National Carbon Policy/Regional Implementation – This Future concentrates on fulfilling a national Carbon Emission Mitigation Policy by constructing generation and transmission within each region to serve the customers within that region.
4. High Energy Efficiency/Demand Response/Distributed Generation/Smart Grid – This Future focuses on developing local programs to avoid the need for large generation and transmission construction.
5. National RPS/National Implementation – Imposes a 30% Renewable Portfolio Standard which may be fulfilled by importing renewable from the areas of the Eastern Interconnection with the highest renewable energy resource potential.
6. National RPS/Regional Implementation – The RPS is assumed to be fulfilled using renewable energy resource potential within each region of the Eastern Interconnection.

7. Nuclear Resurgence – This Future looks at incenting the construction of nuclear technologies as an option on other generation technologies.

8. National Carbon Policy/National Implementation with high Efficiency/Demand Response – This Future combines Future Nos. 2 and 4.

The results from these modeling runs, which include what type of generation is built, where it will be located, how much is needed, and at what cost, can be found at www.eipconline.com. Next, EIPC identified three future scenarios for which a complete transmission build-out will be designed. This exercise will provide an estimate of the transmission costs associated with each scenario. The results of the transmission build-out should be available in early 2012.

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 generator deliverability issues in central Maryland.[35] Deliverability issues can be a result of significant load growth and the retirement of existing generation.[36] 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 15-year horizon to identify transmission constraints and reliability concerns. PJM uses CETO/CETL[37] 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

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

36 Generation slated for retirement includes Benning Road, Buzzard Point, Potomac River, and Gude Landfill in Washington, DC; and Indian River on the Eastern Shore.

37 Capacity Emergency Transfer Objective/ Capacity Emergency Transfer Limit.

deliverability areas ("LDAs") in PJM. The Transmission Expansion Advisory Committee ("TEAC") is the primary forum for stakeholders to discuss the RTEP results. The 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 the North American Electric Reliability Corporation ("NERC")[38] 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 Independent System Operator ("ISO"); ISO New England; the New York ISO; the Tennessee Valley Authority; and the North Carolina Planning Collaborative (added in 2009). 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-Regional Transmission Organization ("RTO") basis, and enhance the physical 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"). This kind of forum has 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

[38] Since 1968, 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 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.

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, CPCNs are required for transmission lines above 69,000 volts or modifications to existing facilities.

4. <u>PJM's Authority</u>

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. PJM has amended the RTEP to include the development of transmission projects to support competition in wholesale electric markets, allowing it to justify projects for economic reasons as well as reliability.

PJM received final FERC approval as an 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. <u>PJM's Definition of Congestion</u>

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 (thereby encompassing the entire PJM wholesale market), prices would be the same across the entire PJM grid. However, the capital investments that would be required for such an expansive transmission system would be cost prohibitive. Therefore, more expensive but advantageously located power plants that generate electricity are required to meet the demand. As a result, LMPs are higher in the congested areas and lower at the source of cheaper power. Congestion costs vary significantly during the course of a day, seasonally, and from year to year. Persistent patterns of high LMPs can indicate future reliability problems and the need for new generation, new transmission, and/or demand response.

2. <u>Location of Congestion</u>

In 2010, the PE South interface continued to be the largest contributor to congestion costs for the third consecutive year. This one constraint's costs were nearly double the sum of all remaining constraint costs. The PE South interface continues to be the primary west-to-east transfer constraint.[39]

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 PJM congestion costs increased by $709.1 million (or 99%) from $719 million in calendar year 2009 to $1,428 billion in calendar year 2010. Maryland utilities shared in these increased congestion costs.

Zone	2010 Total Annual Zonal Congestion Costs ($ million) [40]	2009 Total Annual Zonal Congestion Costs ($ million) [41]
Allegheny Power (Potomac Edison)	282.7	95.3
Baltimore Gas and Electric	91.6	33.5
Delmarva Power	47.2	31.1
Potomac Electric Power	98	58.4

Wholesale prices for electricity are determined in PJM's Reliability Pricing Model ("RPM") Base Residual Auctions ("BRAs"). Blocks of capacity are sold regionally for future delivery. The data below summarizes the annual capacity price for Maryland in 2014/2015 compared to the 2013/2014 delivery year.[42]

Zone	2014/2015 $/MW-Day	2013/2014 $/MW-Day
Western Maryland (PE)	125.94	27.73
Central Maryland (BGE)	136.50	226.15
Central Maryland (PEPCO)	136.50	247.14
Delmarva (DPL)	136.50	245.00
Delmarva South	136.50	245.00

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

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39 Data for 2010. The zones for Allegheny (Potomac Edison), DPL, and Pepco include territory outside of Maryland (Delaware, District of Columbia, Pennsylvania, New Jersey, West Virginia, Virginia). Monitoring Analytics, LLC, *2010 State of the Market Report for PJM*, Table 7-13 (March 10, 2011), *available at:* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml.

40 *Id.* at Table 7-19.

41 Data for 2009. The zones for Allegheny (Potomac Edison), DPL, and Pepco include territory outside of Maryland (Delaware, District of Columbia, Pennsylvania, New Jersey, West Virginia, Virginia). Monitoring Analytics, LLC, 2009 State of the Market Report for PJM, Table 7-17 (March 11, 2010), available at: http://monitoringanalytics.com/reports/PJM _State_of_the_Market/2009.shtml.

42 *2014-2015 RPM Pricing Points*, PJM (May 13, 2011), *available at*: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item08.

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. An ARR provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that results from the annual FTR auction. 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 locational marginal pricing on April 1, 1998. FTRs became available to all transmission service customers and other PJM members with the introduction of the annual FTR auction effective June 1, 2003.

In the 2009 to 2010 planning period, all ARRs and FTRs hedged more than 96.2% of the congestion costs within PJM. During the first seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7% of the congestion costs within PJM.[43,44] For the planning period 2009 to 2010, Potomac Edison and BGE were hedged at greater than 100%, DPL at 55.2%, and Pepco at 19.7%.

Congestion of the electricity transmission grid continues to affect the Baltimore/Washington area and to warrant attention. During the summer of 2010 overall congestion rose by 99%, yet was still lower than congestion costs of 2005. This has resulted primarily from reduced demand and the absence of significant generation or transmission outages. The PJM metered peaks increased for 2010, but 2008 and 2009 were lower than the peaks in 2007 and 2006. This was due to the relatively mild weather, the slowing economy, and increased diversity (non-coincident regional peaks).

For the 2014/2015 capacity auction, PJM announced an increase from the prior 2013/2014 auction in cleared Demand Resources of 4836.5 MW (or 52.1%).

E. High Voltage Transmission Lines in PJM

PJM's 2010 Regional Transmission Expansion Plan was not published until February 2011. However, the PJM Board approved over 400 individual bulk electric system upgrades in 2010. 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 PJM Board has approved more then $19.022 billion of bulk electric system upgrades since the inception of the RTEP process in 1997, ensuring that PJM is compliant with NERC reliability criteria.

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43 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 77% of all Monthly Balance of Planning Period FTRs.

44 *PJM Financial Transmission and Revenue Rights: 2010 State of the Market Report for PJM* (March 10, 2011), *available at*: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec8.pdf.

The deep recession experienced by the country, which began in 2008, continues to have a substantial impact on PJM's RTEP. Load growth is a fundamental driver of resource adequacy and transmission expansion plans. The slow economic recovery has caused PJM to dramatically adjust its backbone transmission line project plans. In particular, the 2011 load forecast issued in January 2011 forecasts significantly lower load growth in the near term than in previous forecasts. Projects of interest to Maryland which have been affected include:

- Potomac-Appalachian Transmission Highline ("PATH") is a 765-kV transmission line that would extend 300 miles from the Amos Substation (Charleston, WV) to the Kemptown Substation in Frederick County, Maryland. This project was docketed as Case No. 9233. Although included in the 2010 RTEP as a baseline transmission project, in an RTEP update for events since December 2010, PJM stated, "Preliminary 2011 PJM RTEP process analysis suggests that the need for the PATH line has moved several years into the future beyond 2015. This has led the PJM Board to direct owners to suspend efforts on the PATH line pending a more complete analysis in the 2011 RTEP." PJM 2010 RTEP 2/28/2010, p. 1.

- Mid-Atlantic Power Pathway ("MAPP") is a 500-kV line that would connect the Possum Point Substation in Virginia and the generation plants in southern Maryland to Vienna and then to Indian River on the Delmarva Peninsula. The portion under the Chesapeake Bay will be a submarine high-voltage direct current line ("HVDC"). This project is docketed as Case No. 9179 at the MD PSC. On Friday August 19, 2011 PHI announced that the new transmission line will be delayed, suggesting that the new in-service date could be between 2019 and 2021.

- Trans-Allegheny Interstate Line ("TrAIL"), 502 Junction to Loudon. Construction was completed on TrAIL in 2011, and its in-service date was June 2011. This 500 kV transmission line runs from near the border of Pennsylvania and West Virginia to northern Virginia.

- Susquehanna to Roseland is a 500-kV line, approximately 130 miles from northern Pennsylvania to northern New Jersey. Although its in-service date technically remains 2012, permitting difficulties will delay this project.

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 currently socialized across all PJM load. The backbone projects listed above have secured incentive rate adders from FERC.[45] To make this determination,

[45] For the MAPP project, FERC granted Pepco a 12.8% return on equity (including incentives), and no rehearing was sought; as well, FERC granted BGE a 12.8% return on equity (including incentives), and denied rehearing. The TrAIL project settled for a 12.7% return on equity (including incentives). FERC granted PATH a 14.3% return on equity (including incentives); however, rehearing remains pending.

FERC requires the applicant to satisfy its nexus test (non-routine project with advanced technology) and address the rebuttable presumption standard (a project required by PJM).

Transmission projects not highlighted above but identified by the transmission owners are listed in Table A-7 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.

V. DEMAND RESPONSE AND CONSERVATION AND ENERGY EFFICIENCY

The Commission recognizes the potential of demand-side management ("DSM") as a powerful tool to bolster energy efficiency and conservation efforts in our State. Furthermore, DSM supports system reliability, energy security, energy and capacity price mitigation (*i.e.*, reducing overall energy costs), and 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 EmPower Maryland,[46] the Commission has required 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 ("Act") was enacted on April 24, 2008. By statute, each utility[47] 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 reduction goals for electric consumption and demand, based on a per capita and 2007 energy consumption baseline. The Act specifically states at § 7-211(g)(1) and (2):

> (1) To the extent that the Commission determines that cost-effective energy efficiency and conservation programs and services are available, for each affected class, 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 the following 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

46 *See* MD. CODE ANN., PUB. UTIL. § 7-211 (2011).

47 The term "Utilities" used in this Section refer to: BGE; DPL; Pepco; PE; and SMECO.

> (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 during 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 of each program planning phase (2008, 2011, 2014), the Act requires each utility to consult with the Maryland Energy Administration ("MEA"), Maryland Public Service Commission Staff ("Staff"), and other stakeholders regarding the design and adequacy of the programs proposed by the utility. The 2011 planning phase began in the summer of 2010 with requests for stakeholder input and progressed through various stages of discussion and refinement. All plans were required to be submitted by September 1, 2011 and hearings regarding the EmPower process took place between October 12, 2011 and October 21, 2011. On December 22, 2011 the Commission approved, with some modifications, the utilities' proposed plans in Commission Order No. 84569.

The Commission's December 22 Order provided increased guidance and framework for the 2012-2014 program cycle. This included standardization of incentive structures, the transition of Limited Income Energy Efficiency programs to the Maryland Department of Housing and Community Development, the creation of various workgroups to enhance and expand program offerings, and necessary updates to budgets and surcharges associated with the EmPower Maryland program.

Commission Order No. 84569 also changes the reporting process for the 2012-2014 cycle. Previously, utility reporting was done on a quarterly basis with an annual summary report filed in January of the following year. The new requirements set forth a semi-annual, formal filing process with required metric submissions filed informally with Staff each quarter. The PSC, in consultation with MEA, will continue to 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.

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, inclusive of their legacy demand response programs – the precursor of these Direct Load Control ("DLC") programs. These programs, although approved separately by the Commission and, in many cases prior to the EmPower Maryland Energy Efficiency and Conservation ("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.

1. DLC Programs

In 2008, the Commission approved the DLC programs of BGE, DPL, Pepco, and SMECO.[48] These utilities filed revised DLC programs as part of the planning process for the 2012-2014 program cycle. Pepco and DPL proposed to expand their respective DLC programs to include Small Commercial as well as Residential, while BGE and SMECO proposed other enhancements to their programs. However, Potomac Edison did not propose a DLC program due to the non-economical projections associated with their DLC program offerings; this decision was consistent with Potomac Edison's 2009-2011 planning proposals.

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, customers can choose one of three cycling choices, 50, 75, or 100 percent.[49] SMECO uses an initial 2 degree offset followed by 30 percent cycling for the thermostats, and a 50 percent cycling option followed by 30

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[48] The Commission approved BGE's PeakRewards Program on November 30, 2007; Pepco and DPL's Energy Wise Programs on April 18, 2008; and SMECO's CoolSentry Program on April 15, 2008. The utilities' 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 the time.

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

percent cycling for the switches during specified time periods. Utilities will invoke the cycling process when PJM calls for an emergency event or a utility-determined event during summer peak season.

The DLC 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' Incentives to DLC Program Participants

Utility	**50% Cycling**		**75% Cycling**		**100% Cycling**		**Bill Credit Month**
	Installation Incentive	**Annual Bill Credit**	**Installation Incentive**	**Annual Bill Credit**	**Installation Incentive**	**Annual Bill Credit**	
BGE	$50	$50	$75	$75	$100	$100	Jun. – Sept.
DPL	$40	$40	$60	$60	$80	$80	Jun.– Oct.
Pepco	$40	$40	$60	$60	$80	$80	Jun.– Oct.
	Installation incentive			**Annual Bill Credit**			**Bill Credit Month**
	Thermostat	**Digital Switch**		**Thermostat**	**Digital Switch**		
SMECO	***	None		$50	$50		Jun.– Oct.

*** A participant in SMECO's 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.

Source: Utilities' EmPower Maryland Energy Efficiency Program Websites.

Table V.B.2 summarizes the progress in installing these devices for each utility DLC program as of December 31, 2010--since each program's inception. Installed devices (programmable thermostats and digital switches) number 403,024 units.

Table V.B.2 Utilities' Direct Load Program Installations; Program-to-Date as of December 31, 2010

Utility	Installed During 2010	Installed PTD as of 12/31/2010
BGE	158,838	326,310
DPL	11,554	13,807
Pepco	36,057	39,987
SMECO	9,599	22,920
Total	216,048	403,024

Source: For BGE, PE and SMECO, Utilities 2010 Quarter 4 Report of EmPower Maryland Program. For DPL and Pepco, Utilities refiling of 2010 made on August 26, 2011.

The DLC program resulted in 803 MW being bid for Delivery Year ("DY") 2013-2014 in the May 2010 PJM RPM auction, a 16 percent decrease from the 2009 bid of 952 MW for DY 2012-2013. To date, these programs have accounted for 3,050 MW of the total capacity bid into PJM's capacity market. Table V.B.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 Bids into PJM BRA (MW)

Utility	DY 2013-2014	DY 2012-2013	DY 2011-2012	DY 2010-2011	DY 2009-2010	Total
BGE*	615	740	512.6	415.4	217.0	2,500
DPL	32.1	38.8	24.7	N/A**	N/A	95
Pepco	124.1	148.7	99.2	N/A	N/A	372
SMECO	31.9	25.0	25.0	N/A	N/A	82
Total	803	952.5	661.5	415.4	217	3049.5

Source: Various data requests in Case Nos. 9111, 9154, 9155, 9156, and 9157.
Notes: *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.

a. *Update on the DLC four programs*

i. *BGE*

BGE launched its DLC program, PeakRewards, in June 2008. Popular to date, PeakRewards installed a total of 158,838 air conditioning cycling devices from January 1, 2010 through December 2010. Approximately 30,000 more devices have been installed through the third quarter of 2011. As of the end of the third quarter of 2011, a total of

356,000 devices (thermostats or switches) have been installed. 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 BRA for six consecutive delivery years (*see* Table V.B.3). The total bid is approximately 2,500 MW, although this total does not reflect the 2014-2015 bid year.[50]

ii. *Pepco*

Pepco launched its Energy Wise program (similar in program design to PeakRewards) in January 2009.[51] Pepco had installed 39,987 devices as of December 2010. The program made significant progress in 2010, with 36,057 devices installed in the year 2010 alone. A further 30,790 devices were installed through the third quarter of 2011. The Company has installed 70,777 devices since the program inception.

Pepco has bid into the last four of PJM's RPM BRAs, with a total bid of 372 MW for all but the 2014-2015 bid year.[52] The Company bid 124 MW for DY 2013/2014 and 149 MW for DY 2012/2013 into PJM's BRA.

iii. *DPL*

Concurrently with Pepco, DPL launched its Energy Wise program in January 2009. The Company had installed 13,807 devices by the end of December 2010. Through the third quarter of 2011 the Company had installed an additional 7,115 devices. Since the inception of the program DPL has installed 20,922 devices.

DPL has bid into the last four of PJM's RPM BRA, with a total bid of 96 MW, excluding the 2014-2015 bid year.[53] The Company bid 32.1 MW for DY 2013/2014, 38.8 MW for DY 2012/2013, and 24.7 MW for DY 2011/2012 into the PJM BRA.

iv. *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

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50 This bid year is not included as bids have not been made public at this time.

51 Pepco and DPL entered into a contract with Comverge on January 20, 2009, and started the testing phase with their own employee volunteers.

52 This bid year is not included as it has not been made public at this time.

53 This bid year is not included as it has not been made public at this time.

to choose a digital switch. SMECO has installed 30,811 devices since program inception, including 11,347 through the third quarter of 2011.

SMECO bid a total of 81.9 MW into PJM's RPM BRA over the last four years, 31.9 MW for DY 2013/2014, and 25 MW for each DY 2011/2012 and 2012/2013.[54]

v. *Suspension of White Rodgers Programmable Thermostat Installation*

In 2010, the Commission suspended the installation of the thermostats used by Pepco, DPL, and SMECO due to a potential safety hazard with the devices. The Commission issued Order No. 83588 on September 23, 2010 directing Pepco, DPL, and SMECO[55] ("the Companies") to cease the installation of the affected thermostats immediately and appear before the Commission at a hearing on September 24, 2010. On September 24, 2010, the Commission issued Order No. 83592 reinforcing the decision to cease thermostat installation in Order No. 83588 and directed the Companies to notify the Commission when the Consumer Protection Safety Commission ("CPSC") issued a decision on corrective actions for the safety issue with the thermostats.

On January 14, 2011 the Companies issued a press release providing further detail about the Canadian CPSC ruling and a subsequent recall by White-Rodgers. On February 1, 2011 the Companies filed a motion to lift the stay, imposed by the Maryland PSC, citing the steps outlined by White-Rodgers to rectify the problem as well as future changes to the program to prevent this type of issue from remaining problematic. On March 7, 2011 the Commission issued Order No. 83899, which lifted the stay on the installation of White-Rodgers thermostats in the manner proposed by the Companies in the February 1 filing.

b. *July 22, 2011 DLC Activation Event*

July 22, 2011 was the first time PJM had declared an emergency event since the Utilities' current DLC programs were approved by the Commission in 2008. BGE was the only utility in Maryland to have an emergency event declared by PJM. This was primarily due to the overheating of a transformer at one of BGE's substations (forcing BGE to take that transformer out of service) and extremely high temperatures. Because of this emergency event, BGE initiated its DLC program at all three cycling levels for the first time (50%, 75%, and 100%), so this was the first time that customers who signed up for the 75% and 100% cycling options had their thermostat or switch cycling at the 75% or 100% level.[56] The combination of the extreme high temperatures, cycling participants for the first time at their selected cycling level, and the length of the event (7.75 hours)[57]

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54 The 2014-2015 bid year is not included as it has not been made public at this time.

55 SMECO also was installing the same White Rodgers programmable thermostats in its CoolSentry program.

56 For non-PJM Emergency events, BGE cycles all participants at a 50 percent level.

57 This total of 7.75 hours was the average time the DLC program was activated, and consisted of two events. The first event was the PJM-declared emergency which lasted for 6 hours and 34 minutes. For the second event, the Company switched all participants to cycle at the 50 percent

led to very high levels of calls to both the BGE call center and the DLC call center, which led to longer than average wait times and customer dissatisfaction.

Pepco, DPL, and SMECO activated their DLC programs for economic reasons and did not experience any above-average duration times or number of calls at their call centers. Pepco, DPL, and SMECO also reported no problems with overloads on their communication systems.

The major problems of the day were due to shortcomings in participant education and communication. The following is a list of education and communication problems and the proposed corrections to avoid these issues in future activations events:

1. **Participants forgot what level of cycling they were signed up for** - BGE (and all the Utilities) need to remind the participants of their cycling level prior to the summer season, when these devices are most likely to be activated. Additionally, BGE should describe situations when a participant might want to lower their cycling level, such as medical conditions or homes with elderly people and small children.
2. **Participants were unaware of the PJM emergency event –** BGE should attempt to contact participants the evening prior to an event (PJM Emergency or BGE initiated), similar to the commitment BGE has made for customer contact for Smart Energy Pricing. That way a participant will be aware of the event beyond the message on the thermostat and light on the switch.
3. **Participants had never been cycled at more than 50% prior to July 22 –** BGE may want to consider cycling participants at their selected cycling level during BGE declared events. Since BGE declared events generally do not last longer than four hours, a 100% participant, for example, may have a better idea of the interior temperature change to expect for a potential PJM declared emergency event.
4. **Long time spent on hold while contacting call center –** BGE has committed, in its report, to increase call center staff during a PJM declared emergency.
5. **Paging signals to DLC devices unable to transmit due to system overloading –** BGE has indicated that it is already working with its signal vendor to configure the system to enable the prioritization of system-wide device commands.

BGE has been working on improving the education and communication issues identified during the July 22 DLC activation event in order to provide more transparency and be more responsive to program participants during future PJM declared emergency events.

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level in order to scale down from the emergency event. The second event lasted for 1 hour and 11 minutes.

2. Peak Load Reduction Forecast

Table V.B.4 demonstrates the impact of demand side management programs on the utilities' peak load forecast. The table presents the 10-year growth rate for gross of demand side management programs and the impact, or net of, those programs during the period of 2011 through 2020. Overall, the peak load forecast for the utilities listed in Table V.B.4 is estimated to result in an 18 percent increase in demand by 2020 without DSM programs. However, net of DSM programs, the overall forecast is expected to result in a 13 percent increase in demand over the 10-year period. Therefore, holding all other factors constant, it is forecasted that the DSM programs will reduce the peak demand growth rate 5 percent by 2020.

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

	Gross of DSM			**Net of DSM (MW)**			**10 Year Growth Rate Variance**
	2011 (MW)	**2020 (MW)**	**10 Year Growth Rate**	**2011 (MW)**	**2020 (MW)**	**10 Year Growth Rate**	
BGE	7,374	8,789	19%	6,699	7,589	13%	6%
DPL	1,249	1,447	16%	1,118	1,255	12%	4%
PE	1,441	1,712	19%	1,412	1,680	19%	0%
Pepco	3,712	4,230	14%	3,322	3,591	8%	6%
SMECO	871	1,080	24%	838	1,031	23%	1%
Total	14,647	17,258	18%	13,389	15,146	13%	5%

Source: Table A-4(a) Peak Summer Demand Forecast Breakdown 2010 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

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 and SMECO); (3) BGE's Smart Grid Initiative,[58] and (4) energy efficiency and conservation programs (BGE, DPL, Pepco, and PE).[59]

C. Energy Efficiency and Conservation Programs

On December 31, 2008, the Commission preliminarily approved 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 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 request for proposals or finalized contracts by March 31, 2009. Comments by the interveners, as well as a response by the utility, were filed in each proceeding. As with the original series of proceedings, the Commission conducted

58 Pepco did not include demand reductions from its Commission-approved AMI initiative.

59 The contribution information is obtained through Staff communication with the utilities. SMECO does not include energy-efficient demand reduction as part of its forecast.

hearings for each utility's proposal. The remaining four utilities' - PE, DPL, Pepco and SMECO - programs were approved in August 2009.

1. <u>EmPower Maryland Policy</u>

The Commission contracted an Independent Evaluator in April 2010 to conduct quality control and due diligence of the Utilities' EM&V programs and contracted evaluator.[60] In an effort to build a credible and reliable EM&V infrastructure, stakeholders and their various evaluators collectively established the Strategic Evaluation Plan in September 2010 which provided guidance on a variety of issues, but also laid out expectations for the Utilities and their evaluator. A baseline study, conducted by KEMA, was completed in 2010 and released in 2011 for use by the utilities and evaluators. 2011 also saw the release of the first round of cost-effectiveness testing. This was a joint effort by the Utilities, stakeholders, Itron, and Navigant Consulting to gather and analyze savings reported under the EmPower Maryland programs and provide an evaluation of the costs and benefits realized by each Utility. Overall, cost-effectiveness testing returned positive results; however, some programs struggled due to their transformative nature. It was determined that these programs may need additional time and attention in order to achieve minimum cost-effectiveness standards.

The five EmPower Maryland Utilities, MEA, the Office of the Peoples Counsel ("OPC") and Staff (hereafter referred to as the "Planning Group") began preparations for the 2012-2014 EmPower Plan filings in the summer of 2010. On September 2, 2010 Staff filed the "Invitation to Stakeholders to Propose New or Revised Programs, Measures or Products" on behalf of the Planning Group ("Invitation"). The Invitation clarified that all cost-effective programs would be considered; however the Utilities would determine what they include in these filings and the utilities have the right to modify, adapt, incorporate and/or implement as they deem appropriate any ideas presented on this process and during the stakeholder sessions. The Invitation included a template intended examine all elements for the implementation of a proposed program or product. Proposals were submitted on October 4, 2010 to Staff and MEA.

Over thirty proposals were submitted. The majority came from organizations or firms that had little or no prior association with demand side stakeholder or work group activities in Maryland. The Planning Group scored proposals largely on the completeness of information provided. Eight organizations or firms were rejected prior to the presentation of proposals in most cases because proposals lacked cost or savings estimates.

Four Work Group meetings starting November 1, 2010, open to all stakeholders, were noticed to Staff's contact list and in a planning framework filed with the Commission. The Planning Group met a number of times during the winter to discuss the merits of the proposals and whether they were likely to be included in some form in the draft Plans. Planning and workgroup meetings continued into 2011 with a culmination in July 2011. As required under the statute each utility and any parties wishing to take part

[60] The Utilities also have their own EM&V evaluator, as does the OPC and the MEA.

in the hearing process were required to file proposals by September 1, 2011. The subsequent EmPower Maryland hearing process lasted eight days and included presentations from the five Utilities, DHCD, Technical Staff, OPC, and MEA, as well as trade organizations and contractors.

2. EmPower Maryland EE&C Programs

On December 31, 2008, by Order Nos. 82383, 82384, 82385, 82386, and 82387,[61] the Commission partially approved the Energy Efficiency, Conservation, and Demand Response Programs pursuant to the EmPower Maryland Energy Efficiency Act of 2008. With the exception of BGE's portfolio, which was approved as a whole, DPL, Pepco, Potomac Edison and SMECO were all requested to make alterations to some program designs as well as revise the total estimated cost and savings with the finalized RFPs. The Commission approved these revised plans in Order Nos. 82825 on August 6, 2009, and 82835, 82836 and 82837 on August 13, 2009. The approved programs are designed for residential customers,[62] as well as small and large commercial businesses.[63] Generally, most programs are designed to provide a rebate to consumers to encourage the purchase of energy-efficient products, equipment, or services.[64]

a. *BGE*

As of the end of the third quarter of 2011 BGE has spent 89 percent of its forecasted 2009-2011 EE&C budget ($149,207,339). The Commission approved BGE's 2011 Residential EE&C EmPower Maryland Surcharge at $0.000730 per kWh effective January, 2011. The Company's EmPower Maryland EE&C Programs have achieved 26 percent of its 2011 energy savings goal (2,052,948 MWh) and 5 percent of the 2011 peak reduction goal (513 MW) through the third quarter of 2011.[65]

b. *Pepco*

As of the end of the third quarter of 2011 Pepco has spent 41 percent of the 2009-2011 EE&C budget ($49.8 million). Pepco continued to use the 2010 combined residential surcharge ($0.00187) as no other surcharge was filed for 2011. The Company has filed a surcharge for 2012 that will encompass the 2010 and 2011 true ups. The Company has achieved 18 percent of its EE&C 2011 energy savings goal (685,378 MWh) and 8 percent of its demand reduction goal (230 MW).

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61 The Commission subsequently approved certain program revisions for BGE in Order No. 82674.

62 Residential programs include Lighting and Appliances; Home Performance with Energy Star, Quick Home Energy Check-up, and Comprehensive Home Audits; Energy Star for New Homes; Limited Income Energy Efficiency Program; Heating, Ventilation, and Air Conditioning ("HVAC") and Domestic Hot Water Heaters. Program availability varies slightly across service territories.

63 Non-residential programs include the C&I Prescriptive; C&I Custom; Commissioning; C&I HVAC. Program availability varies slightly across service territories.

64 All data in the following sections will be current as of the third quarter of 2011 unless otherwise noted. All data is reported at the Wholesale Level.

65 These percentages do not reflect savings from Demand Response programs as these are not part of the EE&C portfolio but are part of the DLC programs.

c. *DPL*

DPL has spent 29 percent of its three-year forecasted budget ($19.6 million). Pepco continued to use its 2010 combined residential surcharge ($0.001822) during 2011. The Company has filed a surcharge for 2012 that will combined the 2010 and 2011 true ups. Energy savings from EE&C programs through the third quarter will amount to 12 percent of the 2011 goal (205,846 MWh) and will account for 4 percent of the 2011 demand reduction goal (73 MW).

d. *SMECO*

Program spending for Residential and C&I EE&C programs through the third quarter accounts for 63 percent of its 2009-2011 forecast ($14.3 million). The Commission approved a residential EE&C surcharge of $0.00145 effective February, 2011. Program-to-date results through the third quarter of 2011 account for 34 percent of the 2011 goal (94,229 MWh) and 40 percent of the 2011 demand reduction goal (29 MW).

e. *PE*

Program spending, through the third quarter of 2011, for EE&C programs accounts for 9 percent of the 2009-2011 forecasted budget. The Commission approved a residential EE&C surcharge of $0.00010 effective for June, 2011. This was a follow up surcharge in response to the approval of the merger with First Energy. Program-to-date results through the third quarter of 2011 account for 30 percent of the 2011 energy savings goal (122,664 MWh) and 15 percent of the 2011 demand reduction goal (49.4 MW).

D. Advanced Metering Infrastructure / Smart Grid

1. <u>Background</u>

"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 can 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 premises capable of being addressed by the utility. Soon the technology will enable customers to see and respond to market-based pricing as well as be more self-aware of their energy usage, assisting in grid reliability and reducing environmental impacts. 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. On September 28, 2007, the Commission issued Order No. 81637, which established the following minimum technical standards for AMI. BGE, Pepco and DPL subsequently filed, for Commission approval, plans seeking to establish an AMI program.

2. Approved AMI Initiatives

a. *BGE*

On August 13, 2010, the Commission issued Order No. 83531 in Case No. 9208,[66] which authorized BGE to deploy its AMI Initiative. Some highlights of the approved AMI Initiative are:

- Install over 2 million electric meters and gas modules;
- Deployment cost of $440 million in capital cost and $57 million in operational costs;
- Total cost over the life of the program of $641 million capital cost and $194 million in operational costs offset by $136 million[67] in federal grants from the Department of Energy;
- Total benefits over the life of the project are estimated at $2.7 billion; and
- 80 percent of all meters to be installed by 2014.

Order No. 83531 directs BGE to do the following:

1) Establish a regulatory asset for the AMI Initiative. Once the Company has delivered a cost-effective AMI system, it may seek cost recovery in its base rates, including incremental costs and net depreciation and amortization costs relating to the meters;
2) Allow cost recovery for the replacement of legacy meters by smart meters to be considered in a future depreciation proceeding;
3) Submit for Commission approval, an updated customer education plan;
4) Develop "a comprehensive set of installation, performance, benefits and budgetary metrics that will allow the Commission to assess the progress and performance of the Initiative;[68] and
5) Notify the Commission of whether it will proceed with the initiative. BGE confirmed its intent to proceed with the initiative in a letter sent to the Commission on August 16, 2010.

Since authorization, BGE, in conjunction with PHI, Staff and other stakeholders, established a Smart Grid Collaborative Work Group per Commission direction. The Work Group offers a venue to discuss issues such as the consumer education plan and the

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66 *In the Matter 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.*

67 BGE was awarded $200 million in American Recovery and Reinvestment Act funding. Of this, $136 million funds AMI deployment and $64 million for Peak Rewards and Customer Care & Billing.

68 Order No. 83531at 48.

comprehensive set of performance metrics. The Company provided an update on deployment efforts at a status conference on December 15, 2010. The Company proposed that deployment take place from 2011-2014, with installation of smart meters beginning in October 2011.

b. *Pepco*

On September 2, 2010, the Commission issued Order No. 83571 in Case No. 9207,[69] authorizing Pepco to deploy its AMI Initiative contingent upon the Company submitting an amended business case and a comprehensive consumer education plan. Some highlights of the approved Smart Grid Initiative are:

- Install 570,000 electric meters;
- Deployment cost of $69.4 million in capital cost;
- Total cost over the life of the program of $127 million in capital cost and $1.038 million in annual incremental operational costs;
- Total benefits over the life of the project are estimated at $311.6 million; and
- Pepco awarded $104.8 million in Smart Grid Investment Grant funds.

Order No. 83571 directs and allows Pepco to do the following:

1) Submit an amended business case and associated benefits-to-costs analysis that demonstrates the cost-effectiveness of the AMI proposal;
2) Submit a plan detailing how it intends to fund its proposed Critical Peak Rebate dynamic pricing structure, including the manner in which it intends to monetize peak demand and energy use reductions attributable to AMI;
3) Develop "a detailed and comprehensive customer education and communications plan," along with a corresponding customer education and communications budget;[70]
4) Develop a comprehensive set of metrics of the Company's AMI proposal, including: (a) installation and performance of the technology; (b) incremental costs incurred; (c) incremental benefits realized; (d) effectiveness of customer education and communications efforts to include customer satisfaction and participation levels; and (e) customer privacy and cyber security;
5) Establish a regulatory asset for the incremental costs associated with the AMI deployment, including start-up costs, which the Company may seek to recover in a base rate proceeding;
6) Seek cost recovery for the replacement of legacy meters by smart meters to be considered in a future depreciation proceeding.

   The Order also prohibits the Company from implementing a Critical Peak Pricing rate structure. A dynamic rate schedule will go in effect once AMI has been installed. Further, the Commission ordered Commission Staff as well as Pepco to convene an AMI working group, which is to include representatives

[69] *In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure*.

[70] *Id*. at 4.

from Pepco, BGE, and the Office of People's Counsel to submit a proposal for "uniformity of critical peak period seasons, times, frequency, and duration, and other aspects of dynamic pricing implementation."[71]

Pepco filed with the Commission its Customer Education Plan on October 15, 2010 and an amended business case on December 13, 2010, in accordance with Order No. 83571. Pepco provided cost-benefit analyses under three different post-deployment scenarios, all of which yielded cost-effectiveness scenarios greater than 1.0. The filing also included depreciation timetables for advanced metering infrastructure and estimated costs for regulatory assets. The consumer education plan and amended business case's final budget—as well as the performance metrics required to be reported— will be subject to the review of the Smart Grid Collaborative Work Group and to the approval of the Commission. In its amended business case filed December 13, 2010, Pepco proposed a time period of 15 months for AMI installation, and the starting month is projected to be June 2011, with completion in August 2012.

c. *DPL*

In Order No. 83571, the Commission deferred the decision on DPL's request to proceed with deployment of its AMI Initiative. DPL's request to establish a regulatory asset for the incremental costs associated with its proposed AMI deployment was deferred as well.

Order No. 83571:

1) Deferred DPL's request to proceed with deployment of its AMI Initiative, and directed the Company to submit an amended business case and associated cost-benefit analysis demonstrating the cost-effectiveness of the proposal;
2) Required the Company to submit a plan detailing how it intends to fund its proposed Critical Peak Rebate dynamic pricing structure, including the manner in which it intends to monetize peak demand and energy use reductions attributable to AMI;
3) Denied DPL's request to establish a regulatory asset for the incremental costs associated with AMI deployment, pending submission of a revised business case of AMI system deployment that is agreeable to the Commission; and
4) Prohibited the Company from implementing a Critical Peak Pricing rate structure.

DPL filed a revised business case for its AMI Initiative on December 14, 2010, which includes forecast scenarios for all of the adjustments specified by Order No. 83571. The Commission reheard the case on August 17, 2011. At this time no order has been issued by the Commission on this issue but one is expected in 2012.

[71] *Id*. at 51.

3. AMI Pilots

a. *SMECO*

SMECO proposed a two-phase AMI Pilot Program to test the operational benefits of AMI deployment, such as savings from eliminating meter readings and improved outage restoration. Phase I of the pilot, approved by the Commission in December of 2009, includes the installation of 1,000 meters in one section of the service territory and went into effect in 2010. The Cooperative will attempt to quantify the level of operational benefits attainable through deployment of AMI, and the Cooperative will report the results of Phase I to the Commission prior to implementing Phase II, which will be a 10,000 meter deployment across the entire service territory. At the time of this report, SMECO had not yet submitted the report on Phase I of the project. SMECO notified Commission Staff that Phase I will commence in mid-March 2011.

4. AMI Workgroups

a. *BGE and Pepco*

Following the Commission's direction that workgroups be established to bring stakeholders together with the utilities for the development of metrics, educational programs, and security standards a number of initiatives were undertaken in 2010 and 2011. In a letter dated February 18, 2011 Pepco received approval from the Commission to implement its "Proposed Phase 1" customer education plan. In a letter dated July 18, 2011 BGE received approval from the Commission to implement its "Smart Grid Customer Education and Communication Plan." In a letter dated August 18, 2011 the Commission granted approval for the Phase 1 Metrics for both BGE and Pepco. The workgroup continues to develop plans for cyber security, Phase II metrics, and Phase II customer education and communication. It is expected that consensus filings and specific plans will be filed for approval on each of these issues in 2012.

E. Mid-Atlantic Distributed Resources Initiative

The Mid-Atlantic Distributed Resources Initiative ("MADRI") was established in 2004, and currently consists of seven PJM State Commissions, DOE and PJM.[72] 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, Commission Staff, FERC, service providers, and consumers. During 2011, MADRI focused on time of use, peak period and related pricing approaches that may be used following the implementation of Smart Grid infrastructure.

VI. ENERGY, THE ENVIRONMENT, AND RENEWABLES

A. 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 ("CO_2"). Under RGGI, ten Northeastern and Mid-Atlantic states have jointly designed a cap-and-trade program that limits permitted carbon dioxide emissions from fossil fuel power plants, and then incrementally lowers that level or "cap" 10% by 2018. The first compliance period spanned January 1, 2009 – December 31, 2011. Nine member states will continue participation in the RGGI program for the second compliance period of January 1, 2012 – December 31, 2014; New Jersey has formally withdrawn from the RGGI program, effective January 1, 2012.

RGGI, Inc. is a nonprofit Delaware corporation formed to provide technical and scientific advisory services to participating states in the development and implementation of the carbon dioxide budget trading programs. The RGGI, Inc. offices are located in New York City in space co-located with the New York Public Service Commission. The RGGI Board of Directors is composed of two representatives from each member state, with equal representation from the states' environmental and energy regulatory agencies. Agency Heads (two from each state), who also serve as RGGI Board members, constitute a steering committee that provides direction to the Staff Working Group and allows coordination of in-process projects for Board review.

Under RGGI, the participating states have agreed to use an auction of allowances as the means to distribute CO_2 emissions allowances to electric power plants regulated under coordinated state CO_2 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 was January 1, 2009. From 2009 through 2014, the cap stabilizes emissions at 2009 levels of approximately 188 million tons annually. These initial base annual emissions budgets for the 2009-2014 periods are summarized in Table VI.A.1.

[72] The Commissions are Delaware, D.C., Illinois, Maryland, New Jersey, Ohio and Pennsylvania.

Table VI.A.1: Annual State CO_2 Allowance Budgets (2009 – 2014)

State	Carbon Dioxide Allowances (in Short Tons)
Connecticut	10,695,036
Delaware	7,559,787
Maine	5,948,902
Maryland	**37,503,983**
Massachusetts	26,660,204
New Hampshire	8,620,460
New York	64,310,805
New Jersey	22,892,730
Rhode Island	2,659,239
Vermont	1,225,830
Total*	**188,076,976**

Source: *Memorandum of Understanding*, REGIONAL GREENHOUSE GAS INITIATIVE (Dec. 20, 2005), *available at* http://www.rggi.org/design/history/mou.
*Note: Following the withdrawal of New Jersey (effective Jan. 1, 2012), the total annual regional cap will be adjusted to 165,184,246 allowances.

Beginning in 2015, the cap is reduced by 2.5% each year until 2018. This phased approach, with initially modest emissions reductions, is intended to provide market signals and regulatory certainty so that electricity generators may begin planning for, and investing in, lower-carbon alternatives throughout the region while avoiding volatile wholesale electricity price impacts and attendant retail electricity rate impacts. The RGGI Memorandum of Understanding apportions carbon dioxide allowances[73] among signatory states through a process that was based on historical emissions and negotiation among the signatory states. Together, the emissions budgets of each signatory state comprise the regional emissions budget, or RGGI "cap."

In 2011, RGGI held four successful auctions for carbon dioxide allowances. As a result of the fourteen auctions comprising the first compliance period, Maryland's Strategic Energy Investment Fund has received a cumulative total of $180,315,817 through December 2011; the Fund received almost $33 million in 2011 alone.[74]

During 2011, auction clearing prices did not recover from the downward trend that started in mid-2009. All allowances sold in 2011 auctions were purchased at the auction floor price.[75] In 2011, the auction floor price was $1.89; the floor price will increase to $1.93 in 2012 auctions.

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73 An allowance is a limited permission to emit one ton of carbon dioxide.

74 *See MD Proceeds by Auction*, REGIONAL GREENHOUSE GAS INITIATIVE, *available at* http://www.rggi.org/docs/MD_Proceeds_by_Auction.pdf (last updated Dec. 12, 2011).

75 *See Auction Results*, REGIONAL GREENHOUSE GAS INITIATIVE, *available at* http://www.rggi.org/market/co2_auctions/results (last updated Dec. 12, 2011).

B. The Renewable Energy Portfolio Standard Program

The Renewable Energy Portfolio Standard ("RPS") Program imposes an annual requirement upon Maryland load serving entities ("LSEs") to derive a percentage of electricity sales from the renewable sources specified in the corresponding RPS Statute.[76] LSEs, which include both electricity suppliers and the utilities that provide Standard Offer Service ("SOS"),[77] file compliance reports with the Commission verifying that the renewable requirement for each entity is satisfied. The RPS obligation applies to anyone who has completed an electricity sale at retail to customers in the State of Maryland. Additional information regarding the status of the Maryland RPS is available in the annual Renewable Energy Portfolio Standard Report submitted to the General Assembly.[78]

On an annual basis each supplier must present renewable energy credits ("RECs") equal to the percentage specified by the RPS Statute,[79] or pay the alternative compliance fees equal to any shortfalls.[80] A REC is equal to one MWh of electricity generated using specified renewable sources.[81] 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 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 generation attributes.[82] A REC has a three-year life during which it may be transferred, sold, or redeemed.[83]

Suppliers that do not meet the annual RPS requirement are required to pay Alternative Compliance Payments ("ACPs") or fees equal to any shortfalls.[84] 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

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76 MD. CODE ANN., PUB. UTIL. § 7-701(j) (2011).

77 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* MD. CODE ANN., PUB. UTIL. §§ 7-501(n) and 7-510(c) (2011).

78 See *Commission Reports*, MARYLAND PUBLIC SERVICE COMMISSION, *available at* http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm (last visited Dec. 2011), for a listing of available RPS Reports submitted in previous years.

79 MD. CODE ANN., PUB. UTIL. § 7-703(b) (2011).

80 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%. 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.

81 MD. CODE ANN., PUB. UTIL. § 7-701(i) (2011).

82 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 Operating Rules, at 3 (September 30, 2010).

83 MD. CODE ANN., PUB. UTIL. § 7-709(d) (2011).

84 MD. CODE ANN., PUB. UTIL. § 7-705(b) (2011).

indirectly spur the creation of new renewable energy sources in the State.[85] The Commission is responsible for creating and administering the RPS Program;[86] responsibility for developing renewable energy resources through loans and grants has been vested with the Maryland Energy Administration.

Eligible fuel sources for Tier 1 RECs and Tier 2 RECs are listed in Table VI.B.1. In order to verify that each LSE 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 of each year.[87] The April 1st deadline provides time for LSEs to calculate electricity sales based on settlement data for the compliance year that ends on December 31st. The April 1st deadline also allows LSEs time to purchase any RECs needed to fulfill their respective RPS obligations.

Table VI.B.1: Eligible Tier 1 and Tier 2 Renewable Sources, for Compliance Year 2010

Tier 1 Renewable Sources	Tier 2 Renewable Sources
• 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) at or above 30 MW • Waste-to-Energy[88]

Source: MD. CODE ANN., PUB. UTIL. § 7-705(b) (2011).
Note: Tier 1 RECs may be used to satisfy Tier 2 obligations; Tier 2 RECs, however, may not be used to satisfy Tier 1 obligations.

85 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. 2008 Md. Laws 846.

86 MD. CODE ANN., PUB. UTIL. § 7-703(a)(1)(i) (2011).

87 These reports have been filed pursuant to MD. CODE ANN., PUB. UTIL. § 7-705(a) (2011).

88 Effective October 1, 2011, new legislation reclassified "waste-to-energy" as a Tier 1 renewable source. 2011 Md. Laws 3045. However, "waste-to-energy" was classified as a Tier 2 renewable source during the 2010 compliance year as reported in this section.

LSEs 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.B.2, Tier 1 and the Tier 1 solar set-aside[89] requirements gradually increase until they peak in 2022 at 18% and 2%, respectively, and are subsequently maintained at those levels. Maryland's Tier 2 requirement remains constant at 2.5% through 2018, after which it sunsets.

Table VI.B.2: Annual RPS Percentage Requirements by Tier

Compliance Year	Tier 1	Tier 1 Solar	Tier 2
2010	3.00%	0.025%	2.50%
2011	4.95%	0.050%	2.50%
2012	6.40%	0.100%	2.50%
2013	8.00%	0.200%	2.50%
2014	10.00%	0.300%	2.50%
2015	10.10%	0.400%	2.50%
2016	12.20%	0.500%	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%	

Source: MD. CODE ANN., PUB. UTIL. § 7-703(b) (2011).
Note: Schedule reflects increased percentage requirements effective January 1, 2011 for the Tier 1 Solar category.

Electricity suppliers not meeting the RPS requirement for any or all tiers of resources pay an ACP on each MW of shortfall.[90] Table VI.B.3 presents the ACP schedule separated by tiers for each year of the RPS from 2010 to 2023 and beyond. Compliance fees, as previously mentioned, are deposited into the SEIF and dedicated to supporting the development of new Tier 1 renewable resources in Maryland.

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

90 MD. CODE ANN., PUB. UTIL. § 7-705(b) (2011).

Table VI.B.3: RPS Alternative Compliance Fee Schedule ($/MWh)

Compliance Year	Tier 1 (non-solar)	Tier 1 Solar	Tier 2	IPL* Tier 1
2010	$20	$400	$15	$5
2011	$40	$400	$15	$4
2012	$40	$400	$15	$4
2013	$40	$400	$15	$3
2014	$40	$400	$15	$3
2015	$40	$350	$15	$2.50
2016	$40	$350	$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

Source: MD. CODE ANN., PUB. UTIL. § 7-705(b) (2011).
*Note: A supplier sale from Industrial Process Load ("IPL") 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 2010 marked the fifth compliance year for the Maryland RPS, and the third year for LSEs to comply with the solar Tier 1 set-aside. GATS and the RPS compliance reports submitted to the Commission by LSEs 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.[91] RPS compliance reports were filed by 58 electricity suppliers, including 33 competitive suppliers, 14 brokers or wholesale electricity suppliers with zero retail electricity sales, and 11 electric companies, of which four are investor-owned utilities. In compliance year 2010, there were approximately 65.6 million MWh of total retail electricity sales in Maryland; 64.1 million MWh of electricity sales were subject to RPS compliance, and 1.5 million MWh were exempt.[92]

91 According to § 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 received the transferred credit; or demonstrated noncompliance by the generating facility with the requirements of § 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 54 – 56 (September 30, 2010).

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

For the 2010 compliance year, electricity suppliers retired 3,569,569 RECs, a quantity greater than the overall RPS obligation for the year by almost 30,000 RECs. According to the compliance reports filed with the Commission, the cost of RECs retired totaled $7,630,526 for the 2010 compliance year. For each of the five compliance years, Table VI.B.4 displays: the breakdown of RECs submitted for each tier in MWh; the number of RECs retired in the year by tier in MWh; and the cumulative tiered shortfalls, in terms of the ACP amount required in dollars per MWh.[93]

Table VI.B.4: RPS Supplier Annual Report Results as of December 31, 2010

RPS Compliance Year		Tier 1 (non-solar)	Tier 1 Solar	Tier 2	Total
2006	RPS Obligation (MWh)	520,073	-	1,300,201	1,820,274
	Retired RECs (MWh)	552,874	-	1,322,069	1,874,943
	ACP Required *($/MWh)*	**$13,293**	**-**	**$24,917**	**$38,209**
2007	RPS Obligation (MWh)	553,612	-	1,384,029	1,937,641
	Retired RECs (MWh)	553,374	-	1,382,874	1,936,248
	ACP Required *($/MWh)*	**$12,623**	**-**	**$23,751**	**$36,374**
2008	RPS Obligation (MWh)	1,183,439	2,934	1,479,305	2,665,678
	Retired RECs (MWh)	1,184,174	227	1,500,414	2,684,815
	ACP Required *($/MWh)*	**$9,020**	**$1,218,739**	**$8,175**	**$1,235,934**
2009	RPS Obligation (MWh)	1,228,521	6,125	1,535,655	2,770,301
	Retired RECs (MWh)	1,280,946	3,260	1,509,270	2,793,475
	ACP Required *($/MWh)*	**$395**	**$1,147,600**	**$270**	**$1,148,265**
2010	RPS Obligation (MWh)	1,922,070	15,985	1,601,723	3,539,778
	Retired RECs (MWh)	1,931,367	15,451	1,622,751	3,569,569*
	ACP Required *($/MWh)*	**$20**	**$217,600**	**$0**	**$217,620**

Sources: Annual Utility RPS Filings with the Commission in years 2007, 2008, 2009, 2010, and 2011. *Commission Reports*, MARYLAND PUBLIC SERVICE COMMISSION, *available at* http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm (last visited Dec. 2011).
*Note: Some electricity suppliers retired more RECs than required by individual RPS obligations.

In 2010 there was a shortfall of 544 MWh in RECs for the Tier 1 Solar requirement of 15,985 MWh—significantly lower than the 2009 Tier 1 Solar REC shortfall of 2,865 MWh. Therefore, the reliance by electricity suppliers on ACPs to fulfill the Tier 1 Solar requirement decreased dramatically between 2009 and 2010. However, the shortfalls associated with the RPS solar obligation still contributed over 99% of the total ACPs due for the 2010 compliance year. The degree to which solar technologies are available to provide renewable output plays a role in the Tier 1 Solar compliance option selected.

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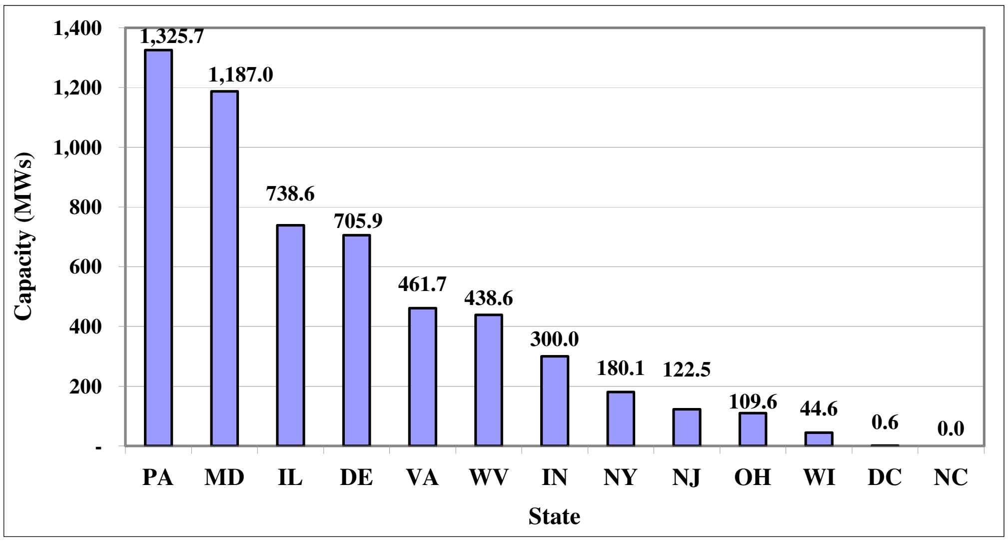
93 The RPS obligation is the total obligation for electricity sales in MWh, which is equal to the number of RECs required for compliance. The number of retired RECs is the actual number of RECs retired for RPS compliance in each corresponding compliance year. The ACP required is calculated by multiplying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

Chart VI.B.5 presents the geographical location and the total generating capacity (5,615 MW) for all Maryland RPS-certified facilities, regardless of tier.[94] RPS requirements also exist in the surrounding states, which generally support out-of-state and regional market participation. Of the renewable facilities that are eligible to participate and potentially provide renewable energy to Maryland, 68 percent are located in the Mid-Atlantic states.[95] The locations of the remaining eligible resources span seven states and in total contribute the remaining 32 percent of the State's eligible capacity.[96]

Chart VI.B.5: Maryland RPS Eligible Capacity by State



Source: PJM-EIS, Generation Attribute Tracking System, Database query, August 2011.

C. 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 supported by an expedited process for the interconnection of solar facilities. Additionally, regulations were adopted that established a mechanism for creating solar renewable energy credits ("SRECs") and a corresponding tracking site. To further streamline the process, an on-line Solar Renewable Energy Facility application form was introduced to the Commission's website. Also, in 2009 the Commission approved

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94 The information in this figure comes from PJM GATS, and does not include Commission authorized renewable energy facilities that have not established a REC account with PJM GATS. Facilities are classified as "MD Certified" if they have applied to the Commission and received an approval number that is recorded in GATS.

95 For this discussion, the Mid-Atlantic states are classified as Pennsylvania, Maryland, Delaware, Virginia, New Jersey, and the District of Columbia ("D.C"). The combined capacity of these Mid-Atlantic state facilities is 3,803.5 MW, or approximately 68% of the total generating capacity of Maryland RPS-certified facilities.

96 The other six states referenced in the text are: Illinois, West Virginia, Indiana, New York, Ohio, Wisconsin, and North Carolina. The combined capacity of these facilities is 1,811.5 MW, or approximately 32% of the total generating capacity of Maryland RPS-certified facilities.

modifications to the solar regulations to reduce the filing requirements for small solar facilities.

For compliance year 2010, an LSE subject to Maryland RPS compliance[97] was obligated to purchase a minimum of 0.025% of its electricity resources from eligible solar sources.[98] The solar RPS obligation increases incrementally each year until reaching the required 2.000% by 2022.[99] If an LSE fails to offset the applicable percentage of retail electricity sales with electricity derived from solar resources or from the purchase of SRECs, then the LSE is responsible for making an alternative compliance payment as set forth in the RPS statute.[100]

An electricity supplier seeking to satisfy its solar RPS obligation may choose to accumulate credits from a renewable on-site generator for purposes of RPS compliance.[101] The rated capacity of the renewable on-site generator governs the minimum contract terms by which the LSE and solar electricity generator must generally abide.

The Maryland Solar RPS grants customers the 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 LSE 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.[102]

An LSE 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% of the compliance fee schedule, with a discount rate that is equal to the Federal Secondary Credit Interest Rate.[103]

Beginning January 1, 2012, electricity generated from a Tier 1 solar renewable source must be connected with the electric distribution grid serving Maryland in order for the generation to be eligible to create Maryland SRECs after that date. Until January 1, 2012, SRECS from non-Maryland Tier 1 solar renewable energy facilities located in PJM are eligible for the Maryland RPS only to the extent that there is a shortage of SRECs derived from facilities interconnected with the Maryland grid. All Maryland-based Tier 1

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97 *See supra* Section VI.B. (discussing entities subject to the RPS obligation).

98 MD. CODE ANN., PUB. UTIL. § 7-703(b) (2011).

99 *See supra* Table VI.B.2.

100 MD. CODE ANN., PUB. UTIL. § 7-705(b) (2011). *See supra* Table VI.B.3.

101 MD. CODE ANN., PUB. UTIL. § 7-709(a) (2011).

102 MD. CODE ANN., PUB. UTIL. § 7-709 (2011).

103 *See* COMAR 20.61.

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. As of August 2011, GATS had registrations for 1,585 solar facilities in Maryland with a total capacity of 25.83 MW.

The decisions made in surrounding states regarding RPS requirements, ACP levels, and the availability of state grants or subsidized loans may potentially impact the Maryland RPS program. The prices that Maryland LSEs will need to offer to obtain RECs in the spot market and under longer term arrangements may reflect the decisions of surrounding states.

VII. ELECTRIC DISTRIBUTION RELIABILITY IN MARYLAND

The Commission supervises and regulates public service companies to promote the economical and efficient delivery of utility services in the State. Economical and efficient delivery of electricity depends on a well-planned, maintained, and operated distribution system.

A. Electric Distribution Reliability Reporting, Operation and Maintenance

Electric utilities serving 40,000 or more Maryland customers are required to file an Annual Reliability Report with the Commission. For each utility, the reports contain measurements of reliability for the preceding calendar year of the System Average Interruption Duration Index ("SAIDI"), the System Average Interruption Frequency Index ("SAIFI") and the Customer Average Interruption Duration Index ("CAIDI").[104] Each investor-owned utility also reports the reliability measurements for a group of the least reliable electric feeders in its system for the year, together 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, together with the remedial actions taken to improve reliability within those districts.

Routine inspection and maintenance of existing distribution system equipment must be performed periodically to help maintain a baseline level of reliability. All electric companies serving Maryland have developed written operation and maintenance ("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 maintain their written O&M procedures with the Commission and to file annual updates of any changes that are made to those procedures. While the procedures vary somewhat from utility to utility, there are many common practices, since

104 CAIDI is calculated by dividing SAIDI by SAIFI.

the procedures should be based on utility experience and accepted good practice within the industry.

With respect to substations, periodic attention is typically given to power transformers, various electrical relays and circuit breakers used primarily for equipment protection, and devices used for controlling voltage such as capacitors and voltage regulators.

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

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 threats to the proper operation of electric and electronic circuits. 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 such 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.

Each utility is required by COMAR to keep sufficient records to demonstrate 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 basic distribution system reliability.

In recent years, electric distribution utilities have made efforts to raise the baseline level of service reliability by increasing the automation of distribution feeders, with the potential to reduce both frequency and duration of sustained electric service interruptions. For example, some feeders can be 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 a feeder experiencing an outage. Currently, many of these switches are manually operated, and require a utility crew to operate the switches 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, new utility operating methods that could serve to improve reliability include more aggressive attempts to reduce the threat of large privately- and publicly- owned trees or large branches falling on overhead power lines. Utilities work to gain tree owner cooperation to allow the removal of large trees near the lines or large branches overhanging the lines, which would help reduce the frequency of service outages, particularly during storms. Other efforts involve limiting the number of customers exposed to any given outage that does occur.

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 reduce outage duration, one common measure of reliability. In addition to crew sharing, the groups hold conference calls for storm preparation for 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

1. <u>Rulemaking No. 43</u>

The Commission instituted Rulemaking No. 43 to adopt service quality and reliability standards. During the pendency of the Rulemaking, the Legislature enacted Chapter 167 of the 2011 Laws of Maryland also requiring the institution of service quality and reliability standards. The Commission convened a working group in this Rulemaking to make recommendation, which recommendations were presented to the Commission on October 27, 2011. The Commission considered the working group’s recommendations and other comments submitted thereon and adopted a set of comprehensive service quality and reliability standards.

The standards include several major categories. The Commission adopted, for publication in the *Maryland Register* for notice and comment,[105] system-wide SAIDI and SAIFI reliability metrics for each of the four investor-owned utilities and the two largest electric cooperatives. The SAIDI and SAIFI metrics are for calendar years 2012-2015, after which the Commission will institute company proceedings to determine future SAIDI and SAIFI reliability metrics. To ensure that groups or pockets of customers do not experience poor reliability, the Commission adopted standards to monitor utility feeders and protective devices that activate multiple times. These two reliability standards require the utilities to improve the performance of the poorest three percent of the utility’s feeders and protective devices that operate five or more times.

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[105] The term “adopted” in this subsection means “adopted for notice and comment.” These standards have not been finally adopted as of December 31, 2011.

Additionally, the Commission adopted standards governing a utility's effort to restore service interruptions. The service interruption standards call for electric service to be restored within certain time periods during normal conditions and when major outage events occur. Major outage events are weather-related or other events that cause an interruption in electric service to 100,000 or 10 percent of a utility's customers, whichever is less.[106] To ensure adequate utility response to downed electric wires, the Commission also adopted standards to direct utility response to hazardous downed wire events.

The reliability and service quality standards also establish customer communication metrics related to how long it takes a utility representative to answer a customer's calls, how many calls are abandoned and how much telephone line capacity is maintained for customer inquires. These standards establish the minimum level of expected service quality. Finally, the Commission adopted comprehensive vegetation management and periodic equipment maintenance standards. These two categories establish minimum practices for utilities when maintaining and operating their electric facilities.

The electric utilities are required to submit annual performance reports to the Commission summarizing electric service quality and reliability results. By July 1st of each year, the Commission shall determine whether each company met its service quality and reliability standards. The first review will be concluded by July 1, 2013 after considering utility performance during 2012.[107] If a utility fails to meet one or more of its standards, the utility must file a corrective action plan if it fails a standard. The Commission will under take appropriate corrective action against a utility that fails to meet a standard, including imposition of appropriate civil penalty.

Electric utilities will need to develop implementation plans or supplement existing plans to ensure their level of performance meets or exceeds the new service quality and reliability standards discussed above.

2. In the Matter of an Investigation into the Reliability and Quality of the Electric Distribution Service of Potomac Electric Power Company – Case No. 9240

As reported in the 2010 Annual Report, on August 12, 2010, the Commission initiated the docketed Case No. 9240 for the purpose of investigating the reliability of Pepco's electric distribution system and the quality of electric distribution service that Pepco is providing to its customers. The initiation of the investigation was based on the unusually large number of complaints from Pepco's customers and their elected officials alleging frequent and lengthy service outages during and after storm events as well as during "blue sky" conditions. Further, customers expressed frustration with the failure of

[106] The interruption must last for 24 or more hours.

[107] The standards adopted by the Commission are anticipated to become effective on July 1, 2012. Thus, the first performance review will cover the portion of 2012 during which the standards are effective.

Pepco's communications system during storm events, which resulted in the customers being unable to obtain estimated times of restoration or report outages. The Commission, in addition to holding a legislative-style hearing in August 2010 for the purpose of questioning the Company's senior executive responsible for system reliability, storm restoration, and customer communications:

- held two evening hearings for public comment to permit members of the public and elected officials to provide their views on Pepco's service quality and reliability;
- issued extensive data requests to the Company to produce documents and information;
- required Pepco to hire an independent consultant to evaluate Pepco's distribution system and communication system ("Consultant"), and directed the Consultant to submit a report of the its findings and recommendations to the Commission; and
- held four days of evidentiary hearings at which the Consultant presented its findings and all parties, as well as the Commission, were able to cross-examine the consultant, the Company's witnesses and the other parties' witnesses on their pre-filed testimony.

Prior to the hearings in August 2010, the Company submitted its Reliability Enhancement Plan for Montgomery County, Maryland ("REP"). According to the Company, the REP was designed to significantly increase the reliability of its distribution system in Maryland over a five-year period and included the following six-point reliability programs: enhanced vegetation management; priority feeders; load growth; distribution automation; URD cable replacement; and selective undergrounding. The Company committed to making adjustments to plan as necessary, as the plan was implemented.

In May 2010, Montgomery County filed its Pepco Work Group Final Report, which contained a series of findings and recommendations by a 12-member Work Group assembled by Montgomery County tasked with investigating the causes of Pepco's frequent electricity outages in the County. The filing of this Work Group Report resulted in a contentious discovery dispute between Pepco and the County. After holding a hearing on the discovery dispute, the Commission issued a subpoena compelling Montgomery County to present a witness or panel of witnesses at the evidentiary hearing to sponsor and answer questions related to the Work Group Report. Montgomery County also responded to the discovery requests.

In addition to the Company's witnesses' pre-filed testimony and the Work Group Report, pre-filed testimony was submitted by Technical Staff of the Commission, Maryland Office of People's Counsel, Maryland Energy Administration, and the City of Gaithersburg. The City of Gaithersburg did not sponsor a witness and its testimony was not admitted into the administrative record. The Apartment and Office Building Association of Metropolitan Washington intervened in the matter, but did not file testimony. The Office of People's Counsel of the District of Columbia petitioned to intervene, but was ultimately granted status as an interested person rather than a party.

On December 21, 2011, the Commission issued Order No. 84564 in which it concluded that, as alleged by its customers, Pepco had failed to provide an acceptable of reliable service during 2010 as well as several of the preceding few years. Similar to the findings of the Consultant, the Commission found that a direct cause of Pepco's low level of reliability was its poor and ineffective maintenance of the vegetation surrounding its sub-transmission and distribution system. Specifically, the Commission pointed to the evidence in the record that Pepco failed to adequately fund its vegetation management, failed to meet its own annual tree trimming goals, and failed to adopt a more aggressive tree trimming practice similar to the practices adopted by other Maryland electric companies after 2001. Moreover, the Commission cited the decline of Pepco's SAIFI figures (adjusted for major outages) during each year from 2004 to 2010 as proof of the steadily deteriorating level of reliability which coincided with Pepco's poor vegetation management practices. These documented failures and deteriorating level of reliability as measured by SAIDI and SAIFI were evidence of the Company's neglectful conduct and poor engineering practices sufficient to constitute a violation of its obligations to provide reliable service to its customers. Further, the Commission found that Pepco failed to conduct periodic inspections of its sub-transmission and distribution lines or to direct after-storm inspections or patrols as required by the National Electrical Safety Code ("NESC") and COMAR 20.50.02.02. Although the Commission held that NESC Rule 214 does not require any precise intervals between inspections, it does require that the Company inspect at intervals experience shows is necessary. The lack of any procedure establishing an interval for periodic inspections reflected that the Company was not complying with the NESC rules or COMAR. Accordingly, based on Pepco's failure to provide its customers reliable service and its violation of the regulations requiring it to periodically inspection its sub-transmission and distribution line, the Commission assessed Pepco a civil penalty of $1 million.

Many of the parties in the matter requested that the Commission, in addition to fining the company, reduce Pepco's authorized return on equity, restrict its payment of dividends to PHI, direct Pepco to waive its monthly customer charge, or modify or revoke Pepco's authority to exercise its franchise. The Commission declined to adopt any of these additional penalties, but it agreed with the Maryland Energy Administration, Office of People's Counsel and Montgomery County that it is

> inequitable for Pepco to have caused significant reliability problems and escalating EIVM costs as a result of years of poorly executed and underfunded vegetation management programs and for the Company's ratepayers to be burdened with full repayment for the EIVM programs that are now required as a direct result of the company's imprudence.[108]

[108] Order No. 84564 at 59.

Specifically, the Commission found that Pepco acted imprudently by: failing to execute adequate vegetation management; by neglecting to conduct periodic inspection or after-storm patrols; by engaging in uncertain and at times contradictory tree trimming practices between 1999 and 2010; and by refusing to transition to a four-year tree trimming cycle, consistent with other Maryland utilities and the recommendations of the tree Trimming Working Group.[109] Because the Commission found that it was highly probably this imprudence increased the cost to ratepayers of the Company's vegetation management programs beyond what they should have been if Pepco had acted prudently, the Commission determined that, in a future rate case, it will disallow recovery of any incremental amounts expended for Pepco's vegetation management programs that is demonstrated to have been caused by Pepco's imprudence.

Additionally, the Commission designed a series of reporting requirements to ensure that Pepco is implementing its REP in a manner that is significantly increasing reliability. Also, in light of the Commission's finding that Pepco's ineffective communications system contributed to significantly to customer dissatisfaction, the Commission directed quarterly reports on Pepco's effort to reform its communications issues. The Commission did not modify Pepco's REP, as requested by certain of the parties, but encouraged Pepco to consider that comments or suggestions of these parties as it conducts its annual review of the REP to determine further updates that will improve reliability. Finally, the Commission warned Pepco that, in the event the periodic reports filed by the Company did not reflect improvement of service reliability, the Commission may consider a larger civil penalty or other additional penalties as justified by the circumstances.

3. Electric Service Interruptions Due to Hurricane Irene

According to the United States Department of Energy ("DOE"), Hurricane Irene made landfall near Cape Lookout, North Carolina as a Category 1 hurricane at 8:00 a.m. EDT on August 27, 2011. In September 2011, the Commission initiated Case No. 9279 to investigate the electric service interruptions due to Hurricane Irene. Maryland's four investor-owned utilities,[110] along with SMECO and Choptank Electric Cooperative filed major storm reports, pursuant to Commission Order No. 84306 and in compliance with COMAR 20.50.07.07 in an effort to detail the utility's response and preparation efforts regarding Hurricane Irene.

According to data provided by utilities, customers began losing power at 7:50 a.m. EDT on August 27, 2011. Power was not restored to more than 99.9% all affected customers until 11:30 p.m. EDT on September 4, 2011.[111] The utilities dispatched approximately 11,882 employees to restore power as a result of Hurricane Irene, with

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[109] *Id.*

[110] BGE, Pepco, Delmarva, Potomac Edison

[111] BGE restored power to 756,016 of the 756,395 affected customers at the declared end of the storm at 11:30 p.m. EDT on Sept. 4. *See* Baltimore Gas and Electric Company Major Storm Report – Hurricane Irene August 27 through September 4, 2011 p 34 for detailed explanation.

nearly half of the employees coming from outside the utility. Out of all of the impacted utilities, BGE experienced the highest peak of customer outages with 476,664; followed by Pepco, 194,516; SMECO, 104,328; Delmarva, 63,597; Choptank, 11,990[112]; and Potomac Edison, peaking with 8,554 customer outages.

On October 31, 2011 the Commission issued Order No. 84445 in the matter of the electric service interruptions due to Hurricane Irene in the State of Maryland beginning August 27, 2011. As a result of this Order, the four IOUs as well as Choptank and SMECO were directed to undertake three specific categories of actions: (1) submit implementation plans in regard to the "lessons learned" issues identified in the respective post-Irene Major Storm Report; (2) participate in a work group tasked with developing standards to provide customers reasonable and reliable estimated time of restoration ("ETR") information; and (3) file with the Commission the protocols used in determining restoration priority.[113]

C. Managing Distribution Outages

An 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 into the OMS. The OMS then can identify what customers were affected by the outage, usually what caused the outage, and when it started and ended.

1. 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 can be used, with assistance from the next two listed inputs, to identify the location of the customer, both in terms of electrical position in the system diagram and geographic position.

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112 *See* Choptank Electric Cooperative Major Storm Report – Hurricane Irene Sept. 21 at 1. The utility explains that it believes the maximum number of peak outages is 11,990 members but the utility's outage management software (OMS), which malfunctioned, reported 8,862 outages. The OMS was used to calculate the Storm Timeline and the data in Figure 1.

113 *See* Commission Order No. 84445, pg. 1-2.

The traditional CIS function will be transformed as some utilities begin to implement elements of Advanced Metering Infrastructure. Advanced electric service meters and associated two-way communications systems between the customer and utility provide an information channel with the potential for use by both parties 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 may 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 Supervisory Control and Data Acquisition ("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 and Work Management System ("WMS"): After an outage is cleared, a work order is closed out within the WMS, and 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.

2. 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 websites 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 large electric cooperatives, Choptank and SMECO, 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. Furthermore, the OMS is expected to evolve in the next few years as a result of the Commission's Order No. 84445 in the matter of the electric service interruptions due to Hurricane Irene in the State of Maryland beginning August 27, 2011. The Order directs the four investor-owned electric utilities and SMECO to participate in a work group tasked with developing standards to provide customers reasonable and reliable ETR information; ETR information is a typical information output from an OMS system.[114] Additionally, Pepco's system tasked with providing customers and emergency management personnel timely outage-related information remains under review in Case No. 9240.

D. Distribution Planning Process

The role of an electric distribution system planner begins with identification of customer needs, both for the near term and the longer term. 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 10 to 20 years, may include expectations of new technologies and altered business climate, in addition to considerations of 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.

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[114] *See* Commission Order No. 84445, pg. 1-2.

1. PE

- In 2012, PE expects to complete construction of two substations, to serve the town of Keedysville and surrounding area, and to serve the area of Lappans Crossroads.
- PE 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.
- PE plans to complete construction in 2013 of a substation to serve the town of Walkersville and the surrounding area.
- In 2014, PE plans to upgrade three substations. The substations supply an area west of Frederick, an area south of Frederick, and the Taneytown area.
- PE plans to complete the construction of a new substation to serve an area around Deep Creek Lake by 2014.
- PE expects to complete a capacity upgrade of a substation serving an area south of Mt. Airy in 2017.
- PE plans to construct a new substation to serve the area southwest of Frederick in 2019.

2. BGE

- BGE plans to construct three additional new substations by the end of 2012. The substations are to serve the Fallston area of Harford County, the Laurel area of Howard County, and the Sykesville area of Carroll County.
- BGE expects to finish the rebuilding of a substation serving northern Baltimore City/Baltimore County in 2012. The utility also expects to complete work to transfer load between feeders and substations to benefit the Westport area of Baltimore City in 2012. The work will retire aging facilities and increase reliability of the network distribution system in the area.
- In 2013, BGE plans to build a new substation to serve load growth in the Konterra Town Center and to relieve other existing substations in the Laurel area. Plans for 2013 also include completing a capacity upgrade in a substation serving Prince George's County.
- BGE plans to complete the construction of two new substations and the rebuilding of two others in 2014. The rebuilding efforts will retire aging facilities and increase electric capacity. These efforts will benefit the Cockeysville and Towson areas of Baltimore County, and the Carroll/Calverton area of Baltimore City.
- Between 2015 and 2016, BGE intends to build five new substations and rebuild two others. The work would provide additional electric capacity to three areas in Harford County, three areas in Baltimore City, and the Hampstead area of Carroll 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.
- Construction of a new substation to serve the Cambridge area is planned for completion by the end of 2012. 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. DPL

- DPL plans to complete the construction of a substation to serve southern Talbot County in 2012.
- To serve southwestern Kent County, DPL plans to construct a substation and extend two feeders in 2013. The utility also intends to complete construction of a new substation that year to serve growing electrical load in Harford County.
- DPL expects to complete the construction of a substation and the extension of three feeders in 2014 to serve Cecil County.
- During 2017, DPL intends to complete construction of a new substation to serve the Queenstown area of Queen Anne's County, and the rebuilding of a substation to serve the Salisbury area.

5. Pepco

- During 2012, Pepco plans to build two new feeders and to extend two others to serve the Lanham area of Prince George's County. Plans for the year also include extending and increasing the capacity of an existing feeder to serve the Greenbelt Station Project.
- 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 plans for 2013 include a capacity upgrade of a substation serving the Colesville, Rossmoor, and Fairland areas of Montgomery County.
- Pepco plans to complete the construction of a substation in 2014 to supply the Westphalia Town Center and the Melwood and Forestville areas of Prince George's County.

- To accommodate the projected demand for electricity in the Hunting Hill, Shady Grove, and Fernwood Road areas of Montgomery County, Pepco plans to complete the construction of two substations by mid-2015. By the close of that year, the utility intends to extend three feeders to serve the Woodmount area of Montgomery County.
- Pepco plans to complete the construction of a new substation in 2017 to accommodate load growth in the Beltsville area of Prince George's County.

6. SMECO

- During 2013, SMECO plans to purchase an additional mobile substation to be used to provide backup power during outage contingency situations in areas where providing backup power through distribution feeder switching is difficult or impossible.

VIII. MARYLAND ELECTRICITY MARKETS

The Electric Customer Choice and Competition Act of 1999 ("Electric Choice Act") established the legal framework for the restructuring and revised regulation of the electric industry in Maryland. The Electric Choice 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. Since 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 Choice Act of 1999. This 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 1, 2011, Maryland has 65 licensed electricity suppliers and 146 licensed electricity brokers.[115] As of December 1, 2011, the following numbers of companies had registered on the Commission's website as actively soliciting new customers in any Maryland service territory: 32 serving residential load, 65 serving industrial load, 70 serving commercial load, and 18 serving other types of load (such as government).

[115] *See* Table A-6.

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 shows that a smaller percentage of residential customers have switched to retail suppliers than non-residential customers. As of September 30, 2011, 19.2% of residential customers, 29.3% of small commercial customers, 56.3% of mid-sized commercial and industrial customers and 91.7% of large commercial and industrial customers were served by retail electricity suppliers. In terms of total electricity supply, almost half of IOU load (47.3%) was served by retail electricity suppliers as of September 30, 2011.

In 2011, residential switching continued to increase as the number of Residential Choice customers increased by 42% statewide. The increase in switching may be due to the availability of savings over the Standard Offer Service rates. Certain 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. The implementation of utility purchase of retail supplier receivables in 2010 for those suppliers that use utility billing probably also played a significant role in the increase in the number of residential customers served by retail electricity suppliers.

The following table illustrates the increase in residential customer switching during 2011:

Table VIII.A.1: Residential Customers Enrolled in Retail Supply

	2010	**2011**	**Annual % Increase**
BGE	179,801	250,856	40%
DPL	12,759	17,481	37%
PE	11,763	16,101	37%
Pepco	64,335	98,310	53%
Md. Total	**268,658**	**382,748**	**42%**

Source: Electric Choice Enrollment Monthly Reports.
Note: 2011 data is as of September 30, 2011.

Between December 2005 and September 2011, the total number of customers statewide served by electricity suppliers increased from 39,527 to 553,438 customers. During the same time, the number of customers served by electricity suppliers in BGE's service territory increased from 3,347 to 339,932.

<u>Table VIII.A.2: Electric Choice Enrollment in Maryland as of September 30, 2011</u>

Number of Customers Served by Competitive Electricity Suppliers

Utilities	Residential	Small C&I	Mid C&I	Large C&I	All C&I	Total
BGE	250,856	28,822	15,037	679	44,538	339,932
DPL	17,481	6,828	2,841	70	9,739	36,959
PE	16,101	6,760	3,211	113	10,084	36,269
Pepco	98,310	11,283	9,196	505	20,984	140,278
Total	**382,748**	**53,693**	**30,285**	**1,367**	**85,345**	**553,438**

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
BGE	23.9%	34.5%	71.0%	95.5%	78.5%	48.7%
DPL	11.8%	38.2%	69.9%	91.8%	70.2%	37.4%
PE	8.1%	34.2%	64.0%	62.4%	61.1%	34.2%
Pepco	21.9%	42.4%	72.1%	94.5%	80.1%	52.7%
Total	**20.9%**	**36.4%**	**70.5%**	**91.1%**	**76.5%**	**47.3%**

<u>Source</u>: Electric Choice Enrollment Monthly Report, Month Ending September 2011.
<u>Notes</u>: Small commercial and industrial ("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. 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* Case Nos. 9037 and 9056 for more information on the Type II customer class. 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.

B. Standard Offer Service

Standard Offer Service ("SOS") is electricity supply service sold by electric utility companies to any customer who does not choose a competitive supplier. The statute requires that SOS should be "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."[116]

Except for Potomac Edison,[117] the investor owned electric companies provide SOS by purchasing wholesale power contracts with two-year terms twice a year, for

116 MD. CODE ANN., PUB. UTIL. § 7-510(c)(4)(ii) (2011).

117 PE procures its residential and small commercial SOS full service requirement through the sealed bid process similar to the other IOUs, but they procure a portion of the SOS load four times a year and the length of the contract varies.

residential and small commercial service of two-year terms, through sealed bid procurements. These procurements take place in the Spring and Fall for service starting the following Fall and Summer; each procurement covers roughly 25% of the total SOS load. Consequently, the SOS price for residential and small commercial customers at any one time reflects an average of market conditions on those four bid days.

SOS for mid-sized non-residential customers is not intended to stabilize prices over an extended period of time. Mid-sized non-residential SOS is procured through sealed bids for three-month contracts procured four times a year. The price of the service at any one time reflects market conditions on the most recent bid day.

SOS for SMECO is procured by the cooperative through an actively managed portfolio approach. Choptank provides SOS through procurement of full-requirements wholesale service through the Old Dominion Electric Cooperative.

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 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. The 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.

The Organization of PJM States, Inc. ("OPSI") is an organization of statutory regulatory agencies in the 13 states and the District of Columbia that form PJM. The Commission is a member of OPSI.

In addition, Maryland falls within the boundaries of Reliability First, one of eight regional entities approved by North America Electric Reliability Council ("NERC") as of January 1, 2006 to develop and enforce regional reliability standards.

1. PJM Interconnection, LLC

PJM, as an RTO, keeps the electricity supply and demand in balance by providing power producers price signals to generate sufficient power to match supply with demand and by adjusting import and export transactions. In managing the grid, the company dispatches about 180,400 MW of generating capacity over 61,200 miles of transmission lines.[118] 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 over a wide area, using an enormous amount of telemetered data from nearly 74,000 points on the grid.[119] This gives PJM a big-picture view of regional conditions and reliability issues, including those in neighboring systems.

PJM also 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.

PJM's members (totaling more than 750) include: power generators, transmission owners, electricity distributors (including Maryland utilities), power marketers and large consumers.[120] The Commission is not a member of PJM (meaning it is unable to cast a vote); however, it does monitor and actively participates in stakeholder and committee processes at PJM.

2. Organization of PJM States, Inc.

OPSI was established in 2005. OPSI, among other things, coordinates activities such as data collection, issue analyses, and policy formulation related to PJM, its operations, its market monitor, and related FERC matters.[121] OPSI provides a means for the PJM states to act in concert with one another when it is deemed to be in their common interest. 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 served as OPSI President during 2009. Commissioner Brenner currently serves as the Commission's member on the OPSI Board of Directors.

During 2011, OPSI was particularly active in facilitating the development of the Independent State Agency Committee ("ISAC"). The purpose of ISAC is to provide PJM with modeling input for potential transmission planning studies. However, no ISAC

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[118] *PJM's Role as an RTO,* PJM (June 1, 2011), http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjms-role-as-an-rto-fact-sheet.ashx.

[119] *Company Overview*, PJM, http://www.pjm.com/about-pjm/who-we-are/company-overview.aspx (last visited December 1, 2011).

[120] *Company Overview*, PJM, http://www.pjm.com/about-pjm/who-we-are/company-overview.aspx (last visited December 1, 2011).

[121] Organization of PJM States, Inc., *available at*: http://www.opsi.us.

member will be bound by the results of any PJM transmission planning study. Furthermore, the participation of any state in ISAC proceedings will not be considered an assessment of the merits of any particular transmission expansion project. As an OPSI Board member, the Commission will serve as the lead agency on ISAC for the State. The Commission continues to be a very active participant in OPSI.

3. Reliability First Corporation

ReliabilityFirst is a not-for-profit company which began operations on January 1, 2006. ReliabilityFirst's mission is to preserve and enhance electric service reliability and security for the interconnected electric systems within the ReliabilityFirst geographic area. The Boundaries of ReliabilityFirst are defined by the service territories of Load Serving Entities and include all of New Jersey, Delaware, Pennsylvania, Maryland, District of Columbia, West Virginia, Ohio, Indiana, Lower Michigan and portions of Upper Michigan, Wisconsin, Illinois, Kentucky, Tennessee and Virginia. ReliabilityFirst's primary responsibilities include developing reliability standards and monitoring compliance to those reliability standards for all owners, operators and users of the bulk electric system and providing seasonal and long-term assessments of bulk electric system reliability within its Region. The Commission monitors ReliabilityFirst activities and comments if necessary.

B. PJM Summer Peak Events of 2010 and 2011

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. The table also shows the average LMP for each Maryland utility zone and for all of PJM at the peak hours.

Table IX.B.1: Summer 2010 and 2011 Coincident Peaks and Zone LMP

Summer 2010 Coincident Peaks				Zone LMP During the Peak				
Day	**Date**	**Hour**	**MW**	**PE**	**BGE**	**DPL**	**PEPCO**	**PJM**
Tuesday	7/6/2010	17:00	136,950	$146.60	$331.01	$332.23	$250.24	$194.70
Wednesday	7/7/2010	17:00	137,788	$139.44	$183.75	$196.80	178.59	$135.93
Friday	7/23/2010	17:00	134,917	$164.76	$271.36	$213.22	$231.33	$169.13
Tuesday	8/10/2010	17:00	132,570	$145.08	$152.42	$137.34	$141.86	$137.93
Wednesday	8/11/2010	17:00	131,949	$129.64	$126.25	$122.75	$153.04	$114.67
Summer 2011 Coincident Peaks				**Zone LMP During the Peak**				
Day	**Date**	**Hour**	**MW**	**PE**	**BGE**	**DPL**	**PEPCO**	**PJM**
Wednesday	6/8/2011	17:00	144,394	$267.88	$422.85	$352.54	$417.40	$279.82
Tuesday	7/19/2011	17:00	145,253	$96.18	$101.78	$104.43	$99.20	$99.25
Wednesday	7/20/2011	17:00	150,121	$179.70	$195.48	$207.51	$186.14	$187.70
Friday	7/21/2011	17:00	158,121	$165.32	$199.17	$196.36	$162.03	$162.36
Thursday	7/22/2011	15:00	152,921	$182.94	$361.51	$407.29	$209.20	$229.54

Source: *Daily Real-Time LMP Files,* PJM MARKETS & OPERATIONS, http://www.pjm.com/markets-and-operations/energy/real-time/lmp.aspx (last visited Nov. 30, 2011).

The 2011 summer peak events in PJM were higher than the summer peak events that occurred in 2010. Table IX.B.1 above shows the summer 2011 and 2010 coincident peaks in PJM and the average real-time LMP by zones located in Maryland during that time period. The summer 2011 peak was 158,121 MW and occurred on July 21, 2011 during the hour ending 5:00 PM Eastern Daylight Time.[122] The summer 2010 peak was 137,788 MW and occurred on July 7, 2010 during the hour ending 5:00 PM Eastern Daylight Time.[123]

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. 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 RTEP to ensure reliability in the PJM region for future years.

122 *Summer 2011 Coincident Peaks,* PJM PLANNING, http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/load-forecast/pjm-5cps-and-w-n-zonal-peaks.ashx (last updated Nov. 21, 2011).

123 *Summer 2010 Coincident Peaks,* PJM PLANNING, http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/load-forecast/summer-2010-peaks-and-5cps.ashx (last updated Nov. 11, 2010).

Using this information, PJM evaluates offers from generators and other resources three years in advance to be available for a one year delivery period running from June through May (up to three years for new generation) through the Base Residual Auction ("BRA").[124] 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.

PJM held the BRA for the 2014/2015 delivery period in May 2011. PJM calculated the RTO reliability requirement to be 148,323.1 MW, which includes a 15.3% 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 2011, 149,974.7 MW cleared the BRA, which essentially increased the reserve margin to 20.6%. This means 1,651.6 MW in excess of the reliability requirement were procured in the BRA. Approximately 10,511.6 MW of excess capacity was offered into the 2014/2015 BRA (*i.e.*, this capacity did not clear); accordingly, for the 2014/2015 delivery year, approximately 12,163.2 MW of capacity in excess of the RTO reliability requirement was offered into the BRA.[125]

The "Net Load" capacity prices for the IOUs in Maryland for each of the eight completed BRAs are presented in Table IX.C.1. The estimated total capacity cost to Maryland of each BRA is also presented. The Net Load capacity price reflects the BRA clearing price and credits from any transmission capacity transfer rights. Maryland has experienced significant volatility in Net Load prices from the past eight BRAs. The Net Load cost to Maryland from the first BRA for the 2007/2008 delivery year was approximately $693 million. By the 2009/2010 BRA, capacity cost had increased to approximately $1.131 billion before declining to $580 million for 2011/2012 and then again increasing to approximately $1.1 billion for 2013/2014. The 2014/2015 BRA experienced another decline in capacity cost, totaling over $700 million. The observed historical pattern of results suggests that future BRA results could vary significantly from year to year and must be closely monitored.

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[124] *Reliability Pricing Model*, PJM MARKETS & OPERATIONS, *available at*: http://www.pjm.org/markets-and-operations/rpm.aspx.

[125] *2014/2015 Base Residual Auction Report*, PJM MARKETS & OPERATIONS, *available at*: http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

Table IX.C.1: RPM "Net Load"[126] Price and Cost

Delivery Year	Potomac Edison ($/MW-day)	BGE ($/MW-day)	DPL ($/MW-day)	Pepco ($/MW-day)	TOTAL Maryland ($)
2007/2008	40.69	139.67	177.00	139.67	693,678,286
2008/2009	113.22	183.03	145.24	183.03	901,994,343
2009/2010	193.80	224.93	193.71	224.78	1,130,545,999
2010/2011	174.29	174.29	178.27	174.29	920,141,784
2011/2012	110.04	110.04	110.04	110.04	579,821,643
2012/2013	16.46	129.63	162.99	129.63	636,535,392
2013/2014	27.73	223.85	240.41	236.93	1,100,652,116
2014/2015	125.94	135.25	142.99	135.25	711,062,492

Source: *RPM Auction User Information*, PJM MARKETS & OPERATIONS, *available at*: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01.

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, Day-Ahead Scheduling Reserve, and Regulation markets. 15,545 MW of demand resources were offered into the 2014/2015 BRA, which represents an increase of 20% over the amount offered into the 2013/2014 BRA.[127] Of that amount, 14,118 MW cleared, which is 4,836.5 MW greater than that which cleared in the 2013/2014 BRA.[128]

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 their electricity usage in the circumstances of either peak periods or unexpected outages.

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126 The "Net Load" price for each company is the RPM auction price adjusted for any capacity transfer credits and load variations from forecast. The total Maryland cost assumes a constant demand for the periods shown based on the summer peak load contribution for each company's transmission zone. The PE zone includes PE, the municipal electric companies of Hagerstown, Thurmont, Williamsport, and Somerset Rural Electric Cooperative electric loads. The DPL zone includes DPL Maryland, Choptank, the municipal electric companies of Easton, Berlin, and A&N Electric Cooperative loads. The Pepco zone includes Pepco Maryland and SMECO loads.

127 *2014/2015 RPM Base Residual Auction Results*, PJM MARKETS & OPERATIONS (Nov. 18, 2010), http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx. The newly integrated American Transmission Systems, Inc. ("ATSI") transmission zone accounted for 1,384 MW of the total increase, while the other transmission zones accounted for the remaining 1,720 MW. *Id.* at 2.

128 *Id.*

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 in either the energy market or the ancillary services market, which includes reserve and regulation. Payments in the energy market generally are based upon the difference between retail rates and day ahead or real-time LMP. Customers who elect to have their load reductions dispatched by PJM are guaranteed to receive a payment equal to their offer into the market. Payments in the ancillary services markets generally are based upon the market clearing price.

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 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, but customers who elect to have their load reductions dispatched by PJM are guaranteed to receive a payment equal to their offer into the market, including shutdown costs. The 2014/2015 BRA is the first under which two additional demand resource products were offered: Annual DR which is available throughout the year, and Extended Summer DR, which is available for an extended summer period. These new products have fewer limitations than the current DR product.

X. PROCEEDINGS BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

The Commission is actively engaged in wholesale energy market policy development at PJM. While the Commission is not a formal stakeholder in the stakeholder process, the Commission does actively engage on issues and voice its concerns regularly, both independently and as part of OPSI. The Commission participates in the policy development process because decisions made at PJM directly affect the price of electricity and related services to Maryland customers.

PJM holds more than 300 stakeholder meetings each year for more than two dozen committees, subcommittees, task forces, and working groups. The Commission assigns one or more Commission Advisors to represent the Commission at the major policy-setting groups. These groups include the Members Committee, the Markets & Reliability Committee, the Markets Implementation Committee, the Planning Committee, and the Regional Planning Process Task Force. Other Commission Staff cover technical and engineering-related meetings, such as the Transmission Expansion Advisory

Committee, Resource Adequacy Analysis Subcommittee, Demand Response Subcommittee, and the Load Analysis Subcommittee.

Some of the issues in which the Commission is regularly engaged include load forecasting, demand response, price responsive demand, the capacity market, shortage pricing, governance, transmission planning and reliability planning criteria. While many of these issues are ultimately litigated at FERC, where the Office of General Counsel represents the Commission, being involved in PJM's stakeholder process gives the Commission early input into the important issues as they emerge.

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 licensed electricity and natural gas suppliers and brokers in Maryland, renewable energy projects, planned transmission enhancements, and potential new power plants in Maryland.

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 2011 data request for the Ten-Year Plan.

Table A-2: Number of Customers by Customer Class as of December 31, 2010

	System Wide						Maryland					
Utility/Co.	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	1,968	293	112	18	0	2,391	1,968	293	112	18	0	2,391
BGE	1,114,712	118,575	5,536	0	0	1,238,823	1,114,712	118,575	5,536	0	0	1,238,823
Choptank	47,179	4,787	22	255	0	52,243	47,179	4,787	22	255	0	52,243
DPL	287,398	58,688	451	648	0	347,185	94,414	25,577	241	274	0	120,506
Easton	96,779	23,388	0	0	0	120,167	96,779	23,388	0	0	0	120,167
Hagerstown	14,798	2,471	123	0	0	17,392	14,798	2,471	123	0	0	17,392
PE	334,650	42,838	4,841	665	3	382,997	220,576	27,186	2,861	345	3	250,971
PEPCO	713,148	73,782	0	1,368	0	788,298	483,906	47,349	0	1,336	0	532,591
SMECO	136,191	13,641	6	314	0	150,152	136,191	13,641	6	314	0	150,152
Somerset	12,212	1,157	6	0	0	13,375	754	37	3	0	0	794
Thurmont	2,441	332	10	43	0	2,826	2,441	332	10	43	0	2,826
Williamsport	857	72	32	44	0	1,005	857	72	32	44	0	1,005
Total	**2,762,333**	**340,024**	**11,139**	**3,355**	**0**	**3,116,854**	**2,214,575**	**263,708**	**8,946**	**2,629**	**3**	**2,489,861**

Source: Company data responses to Table A-2 in the Commission's 2011 data request for the Ten-Year Plan.
Note: A&N did not provide the requested information.

Table A-3: Typical Monthly Electric Bills in Maryland (Winter 2010)

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility/Co.	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other
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	1,661	1,227	8,969	1,663	249.44	238.28	1503.62	395.73	0.1502	0.1942	0.1676	0.2380
BGE	1,251	11,886	47,477	N/A	182.71	559.00	961.39	N/A	0.1461	0.0470	0.0202	N/A
Choptank	1,406	3,506	308,531	272	184.72	443.72	29175.09	71.07	0.1314	0.1266	0.0946	0.2622
DPL	1,327	5,547	130,086	3,868	181.05	290.35	2102.04	854.09	0.1365	0.0523	0.0162	0.2208
Easton	1,527	6,243	N/A	N/A	155.56	670.72	N/A	N/A	0.1019	0.1074	N/A	N/A
Hagerstown	1,110	2,720	71,329	N/A	111.35	284.09	6576.78	N/A	0.1003	0.1045	0.0922	N/A
PE	1,540	7,687	51,412	N/A	157.36	922.68	4842.91	N/A	0.1022	0.1200	0.0942	N/A
PEPCO	1,227	15,030	3,298,402	82,154	165.23	675.11	49027.70	3249.22	0.1347	0.0449	0.0149	0.0396
SMECO	750	12,500	200,000	N/A	108.11	1533.73	21324.05	N/A	0.1442	0.1227	0.1066	N/A
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	1,896	4,606	252,541	1,608	197.70	451.74	22478.08	180.27	0.1043	0.0981	0.0890	0.1121
Williamsport	974	1,872	16,512	1,641	95.23	189.34	1657.44	154.06	0.0977	0.1011	0.1004	0.0939
Total	14,669	72,824	4,385,259	91,205	1788.46	6258.76	139649.10	4904.45	1.3494	1.1189	0.7959	0.9666

Source: Table A-3 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.
Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.
Note: Winter is defined as Dec. 1 through Feb. 29--as defined by PJM.
Note: A&N did not provide the requested information.

Table A-4(a): System Wide Peak Demand Forecast as of December 31, 2010 (MW) (Net of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2011	4	6,699	232	3,979	68	68	2,691	6,593	838	20	5	**21,196**
2012	4	6,710	236	3,892	69	63	2,712	6,538	836	20	5	**21,084**
2013	4	6,880	248	3,871	71	63	2,728	6,535	851	20	5	**21,274**
2014	4	6,840	257	3,878	72	63	2,750	6,562	867	20	5	**21,317**
2015	4	6,802	266	3,887	73	64	2,773	6,586	882	20	5	**21,361**
2016	4	6,728	276	3,920	74	64	2,809	6,623	897	20	5	**21,420**
2017	5	6,822	287	3,960	75	64	2,844	6,682	913	20	5	**21,676**
2018	5	6,917	297	4,007	77	65	2,883	6,743	928	20	5	**21,945**
2019	5	7,014	307	4,059	78	65	2,925	6,825	943	20	5	**22,245**
2020	5	7,112	318	4,120	79	65	2,969	6,901	958	20	5	**22,552**
2021	5	7,213	329	4,167	80	66	3,012	6,957	973	20	5	**22,827**
2022	5	7,314	341	4,217	82	66	3,061	7,018	987	20	5	**23,115**
2023	6	7,407	354	4,267	83	66	3,113	7,077	1,002	20	5	**23,398**
2024	6	7,497	367	4,318	84	67	3,168	7,144	1,017	20	5	**23,692**
2025	6	7,586	381	4,367	85	67	3,217	7,207	1,031	20	5	**23,971**
Change (MW) (2011-2025)	**2**	**887**	**149**	**388**	**17**	**(1)**	**526**	**614**	**193**	**-**	**-**	**2,775**
Percent Change	**47.50%**	**13.24%**	**64.42%**	**9.75%**	**25.38%**	**-1.91%**	**19.54%**	**9.31%**	**23.05%**	**0.00%**	**0.00%**	**13.09%**
Annual Growth Rate	**2.82%**	**0.89%**	**3.62%**	**0.67%**	**1.63%**	**-0.14%**	**1.28%**	**0.64%**	**1.49%**	**0.00%**	**0.00%**	**0.88%**

Source: Table A-4 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

Table A-4(b): Maryland Peak Demand Forecast as of December 31, 2010 (MW) (Net of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2011	4	6,699	232	1,118	68	68	1,412	3,322	838	20	5	**13,786**
2012	4	6,710	236	1,117	69	63	1,415	3,237	836	20	5	**13,711**
2013	4	6,880	248	1,117	71	63	1,414	3,246	851	20	5	**13,918**
2014	4	6,840	257	1,116	72	63	1,420	3,256	867	20	5	**13,919**
2015	4	6,802	266	1,111	73	64	1,426	3,261	882	20	5	**13,913**
2016	4	6,728	276	1,121	74	64	1,445	3,281	897	20	5	**13,914**
2017	5	6,822	287	1,133	75	64	1,463	3,312	913	20	5	**14,098**
2018	5	6,917	297	1,147	77	65	1,483	3,344	928	20	5	**14,287**
2019	5	7,014	307	1,163	78	65	1,506	3,388	943	20	5	**14,493**
2020	5	7,112	318	1,181	79	65	1,531	3,428	958	20	5	**14,702**
2021	5	7,213	329	1,195	80	66	1,556	3,458	973	20	5	**14,900**
2022	5	7,314	341	1,210	82	66	1,585	3,490	987	20	5	**15,105**
2023	6	7,407	354	1,225	83	66	1,617	3,522	1,002	20	5	**15,305**
2024	6	7,497	367	1,241	84	67	1,651	3,557	1,017	20	5	**15,511**
2025	6	7,586	381	1,255	85	67	1,680	3,591	1,031	20	5	**15,707**
Change (MW) (2011-2025)	**2**	**887**	**149**	**138**	**17**	**(1)**	**267**	**268**	**193**	**-**	**-**	**1,921**
Percent Change	**47.50%**	**13.24%**	**64.42%**	**12.33%**	**25.38%**	**-1.91%**	**18.91%**	**8.08%**	**23.05%**	**0.00%**	**0.00%**	**13.93%**
Annual Growth Rate	**2.82%**	**0.89%**	**3.62%**	**0.83%**	**1.63%**	**-0.14%**	**1.24%**	**0.56%**	**1.49%**	**0.00%**	**0.00%**	**0.94%**

Source: Table A-4 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

Table A-4(c): System Wide Peak Demand Forecast as of December 31, 2010 (MW) (Gross of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2011	11	7,374	242	4,148	68	68	2,720	6,986	871	20	5	**22,512**
2012	11	7,471	246	4,173	69	63	2,757	7,095	878	20	5	**22,787**
2013	11	7,596	258	4,226	71	63	2,787	7,192	897	20	5	**23,124**
2014	11	7,717	267	4,278	72	63	2,825	7,271	915	20	5	**23,443**
2015	11	7,833	276	4,328	73	64	2,864	7,339	931	20	5	**23,742**
2016	11	7,931	286	4,361	74	64	2,903	7,376	946	20	5	**23,977**
2017	11	8,025	297	4,401	75	64	2,935	7,435	962	20	5	**24,229**
2018	12	8,120	307	4,448	77	65	2,971	7,496	977	20	5	**24,496**
2019	12	8,217	317	4,500	78	65	3,010	7,578	992	20	5	**24,792**
2020	12	8,315	328	4,561	79	65	3,049	7,654	1,007	20	5	**25,094**
2021	12	8,416	339	4,608	80	66	3,085	7,710	1,022	20	5	**25,362**
2022	12	8,507	351	4,658	82	66	3,124	7,771	1,036	20	5	**25,631**
2023	12	8,610	364	4,708	83	66	3,164	7,830	1,051	20	5	**25,913**
2024	13	8,700	377	4,759	84	67	3,210	7,897	1,066	20	5	**26,196**
2025	13	8,789	391	4,808	85	67	3,249	7,960	1,080	20	5	**26,467**
Change (MW) (2011-2025)	**2**	**1,415**	**149**	**660**	**17**	**(1)**	**530**	**974**	**209**	**-**	**-**	**3,955**
Percent Change	**17.59%**	**19.19%**	**61.72%**	**15.91%**	**25.38%**	**-1.91%**	**19.48%**	**13.94%**	**23.96%**	**0.00%**	**0.00%**	**17.57%**
Annual Growth Rate	**1.16%**	**1.26%**	**3.49%**	**1.06%**	**1.63%**	**-0.14%**	**1.28%**	**0.94%**	**1.55%**	**0.00%**	**0.00%**	**1.16%**

Source: Table A-4 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

Table A-4(d): Maryland Peak Demand Forecast as of December 31, 2010 (MW) (Gross of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2011	11	7,374	242	1,249	68	68	1,441	3,713	871	20	5	**15,061**
2012	11	7,471	246	1,256	69	63	1,459	3,770	878	20	5	**15,248**
2013	11	7,596	258	1,272	71	63	1,474	3,822	897	20	5	**15,487**
2014	11	7,717	267	1,288	72	63	1,495	3,864	915	20	5	**15,716**
2015	11	7,833	276	1,303	73	64	1,517	3,900	931	20	5	**15,932**
2016	11	7,931	286	1,313	74	64	1,538	3,920	946	20	5	**16,107**
2017	11	8,025	297	1,325	75	64	1,554	3,951	962	20	5	**16,288**
2018	12	8,120	307	1,339	77	65	1,572	3,984	977	20	5	**16,475**
2019	12	8,217	317	1,355	78	65	1,591	4,027	992	20	5	**16,677**
2020	12	8,315	328	1,373	79	65	1,611	4,068	1,007	20	5	**16,881**
2021	12	8,416	339	1,387	80	66	1,628	4,097	1,022	20	5	**17,072**
2022	12	8,507	351	1,402	82	66	1,648	4,130	1,036	20	5	**17,258**
2023	12	8,610	364	1,417	83	66	1,669	4,161	1,051	20	5	**17,457**
2024	13	8,700	377	1,433	84	67	1,693	4,197	1,066	20	5	**17,652**
2025	13	8,789	391	1,447	85	67	1,712	4,230	1,080	20	5	**17,839**
Change (MW) (2011-2025)	**2**	**1,415**	**149**	**199**	**17**	**(1)**	**271**	**518**	**209**	**-**	**-**	**2,779**
Percent Change	**17.59%**	**19.19%**	**61.72%**	**15.91%**	**25.38%**	**-1.91%**	**18.82%**	**13.94%**	**23.96%**	**0.00%**	**0.00%**	**18.45%**
Annual Growth Rate	**1.16%**	**1.26%**	**3.49%**	**1.06%**	**1.63%**	**-0.14%**	**1.24%**	**0.94%**	**1.55%**	**0.00%**	**0.00%**	**1.22%**

Source: Table A-4 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

Table A-5(a): System Wide Energy Sales Forecast (GWh) (Net of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2011	41	31,991	953	12,579	275	337	14,135	26,574	3,534	85	20	**90,525**
2012	41	31,963	975	12,696	278	307	14,358	26,840	3,567	85	20	**91,130**
2013	41	32,002	995	12,777	281	310	14,503	27,070	3,631	85	20	**91,714**
2014	41	32,461	1,008	12,864	283	313	14,697	27,284	3,693	85	20	**92,750**
2015	42	32,938	1,029	13,007	286	316	14,885	27,590	3,755	85	20	**93,952**
2016	42	33,382	1,047	13,181	289	319	15,100	27,954	3,818	85	20	**95,238**
2017	43	33,931	1,066	13,365	291	323	15,321	28,272	3,877	85	20	**96,593**
2018	43	34,488	1,087	13,573	294	326	15,550	28,636	3,937	85	20	**98,039**
2019	44	35,054	1,106	13,835	297	336	15,787	29,057	3,992	85	20	**99,613**
2020	45	35,628	1,126	14,126	299	329	16,012	29,547	4,045	85	20	**101,262**
2021	45	36,212	1,146	14,371	302	332	16,256	29,979	4,098	85	20	**102,848**
2022	46	36,805	1,168	14,892	305	336	16,510	29,432	4,147	85	20	**103,746**
2023	47	37,408	1,191	15,130	307	339	16,775	29,779	4,200	85	20	**105,281**
2024	48	38,020	1,215	15,356	310	342	17,047	30,147	4,250	85	20	**106,840**
2025	48	38,642	1,241	15,633	313	346	17,315	30,570	4,299	85	20	**108,512**
Change (GWh) (2011-2025)	**7**	**6,651**	**288**	**3,054**	**37**	**9**	**3,180**	**3,996**	**765**	**-**	**-**	**17,987**
Percent Change	**18.39%**	**20.79%**	**30.22%**	**24.27%**	**13.55%**	**2.77%**	**22.49%**	**15.04%**	**21.64%**	**0.00%**	**0.00%**	**19.87%**
Annual Growth Rate	**1.21%**	**1.36%**	**1.90%**	**1.56%**	**0.91%**	**0.20%**	**1.46%**	**1.01%**	**1.41%**	**0.00%**	**0.00%**	**1.30%**

Source: Table A-5 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

Table A-5(b): Maryland Energy Sales Forecast (GWh) (Net of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2011	41	31,991	953	4,279	275	337	7,392	15,105	3,534	85	20	**64,012**
2012	41	31,963	975	4,311	278	307	7,497	15,065	3,567	85	20	**64,109**
2013	41	32,002	995	4,348	281	310	7,542	15,186	3,631	85	20	**64,440**
2014	41	32,461	1,008	4,379	283	313	7,632	15,255	3,693	85	20	**65,170**
2015	42	32,938	1,029	4,433	286	316	7,722	15,407	3,755	85	20	**66,032**
2016	42	33,382	1,047	4,478	289	319	7,835	15,571	3,818	85	20	**66,887**
2017	43	33,931	1,066	4,515	291	323	7,956	15,732	3,877	85	20	**67,839**
2018	43	34,488	1,087	4,557	294	326	8,080	15,915	3,937	85	20	**68,831**
2019	44	35,054	1,106	4,606	297	336	8,208	16,112	3,992	85	20	**69,860**
2020	45	35,628	1,126	4,675	299	329	8,329	16,358	4,045	85	20	**70,938**
2021	45	36,212	1,146	4,734	302	332	8,464	16,616	4,098	85	20	**72,056**
2022	46	36,805	1,168	4,808	305	336	8,609	16,315	4,147	85	20	**72,643**
2023	47	37,408	1,191	4,867	307	339	8,763	16,540	4,200	85	20	**73,768**
2024	48	38,020	1,215	4,920	310	342	8,922	16,733	4,250	85	20	**74,865**
2025	48	38,642	1,241	4,993	313	346	9,076	16,978	4,299	85	20	**76,041**
Change (GWh) (2011-2025)	**7**	**6,651**	**288**	**714**	**37**	**9**	**1,684**	**1,873**	**765**	**-**	**-**	**12,029**
Percent Change	**18.39%**	**20.79%**	**30.22%**	**16.69%**	**13.55%**	**2.77%**	**22.78%**	**12.40%**	**21.64%**	**0.00%**	**0.00%**	**18.79%**
Annual Growth Rate	**1.21%**	**1.36%**	**1.90%**	**1.11%**	**0.91%**	**0.20%**	**1.48%**	**0.84%**	**1.41%**	**0.00%**	**0.00%**	**1.24%**

Source: Table A-5 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

Table A-6: Maryland Licensed Electric/Natural Gas Suppliers and Brokers as of December 1, 2011

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
5Linx Enterprises, Inc.		IR-2167		IR-2166
A Better Choice Energy Services		IR-1697		IR-1698
Acclaim Energy, Ltd.		IR-1726		IR-1728
Advantage IQ, Inc.		IR-2240		IR-2242
Affiliated Power Purchasers International, LLC		IR-279		IR-2127
Affinity Energy Management, LLC		IR-2016		IR-2104
Allegheny Energy Supply	IR-229		IR-229	
Alphabuyer, Inc.		IR-2214		IR-2217
Ambit Northeast, LLC	IR-1992		IR-1993	
Ameresco, Inc.		IR-2145		IR-2144
Amerex Brokers, LLC		IR-1513		IR-1512
America Approved Commercial, LLC		IR-2174		
America Approved Energy Services Direct, LLC		IR-1841		
American Power Partners LLC	IR-2142			
American PowerNet Management, L.P.	IR-604			
AOBA Alliance, Inc.		IR-267		IR-375
AP Gas & Electric (MD), LLC d/b/a APG&E	IR-2231			
API Ink, LLC		IR-1399		
ARS International, Inc.		IR-1181		
Avalon Energy Services, LLC		IR-1693		IR-1743
Better Cost Control, LLC d/b/a Ardor Power		IR-2082		
BGE Home Products and Services, Inc. also d/b/a BGE Commercial Building Systems			IR-311	
BGE Home Products and Services, Inc. also d/b/a BGE Commercial Building Systems d/b/a Constellation Electric	IR-228			
BidURenergy, Inc.		IR-1847		IR-1846
BlueStar Energy Services	IR-757			
Bmark Energy, Inc.		IR-2018		
Bollinger Energy Corporation		IR-265	IR-322	
BP Energy Company			IR-676	
BTU Energy, LLC		IR-864		
C & D Commercial Brokerage, Inc. t/a Capital Energy Solutions		IR-1823		
Castlebridge Energy Group	IR-1735			
Castlebridge Energy Group, LLC			IR-2331	
CCES, LLC	IR-2161			
Champion Energy Services, LLC	IR-2196			
Chesapeake Energy Services, Inc.		IR-1638		
Choice! Energy Services		IR-682		
Clean Currents, LLC		IR-980		IR-1782
Clearview Electric, Inc.	IR-2009			
Coastal Energy Company, LLC		IR-1900		
Co-eXprise, Inc.		IR-879		IR-879
Coleman Hines, Inc.		IR-1389		
Colonial Energy, Inc.			IR-606	
Commerce Energy, Inc.	IR-639		IR-737	

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Commercial and Industrial Energy Solutions, LLC		IR-2062		
Commercial Utility Consultants, Inc.		IR-2361		
Compass Energy Services			IR-652	
Competitive Energy Services-Maryland, LLC		IR-895		IR-895
ConocoPhillips Company			IR-1359	
ConocoPhillips, Inc.			IR-378	
Consolidated Edison Solutions, Inc.	IR-603			
Constellation Energy Projects and Services Group, Inc.	IR-239			
Constellation NewEnergy, Inc.	IR-500		IR-522	
Constellation NewEnergy-Gas Division, LLC			IR-655	
Consumer Energy Solutions, Inc.		IR-1210		
Coral Energy Gas Sales, Inc.			IR-360	
CQI Associates, LLC		IR-575		IR-1753
Creativ Energy Options		IR-1528		
Current Choice, Inc.		IR-2153		
Cybermark Systems, Inc. d/b/a Proenergy Consultants		IR-1785		
Cypress Natural Gas, L.L.C.			IR-674	
DD&J LLC		IR-1560		
Delta Energy, LLC			IR-645	
Direct Energy Business f/k/a Strategic Energy	IR-437			
Direct Energy Services, LLC	IR-719		IR-791	
Dominion Retail, Inc. t/a Dominion Energy Solutions	IR-252		IR-345	
Downing Place, LLC		IR-2011		
DTE Energy Trading, Inc.	IR-686			
E Source Companies, LLC		IR-2017		IR-2021
Early Bird Power		IR-1798		
Eastern Shore of Maryland Educational Consortium Energy Trust dba ESMEC Energy Trust		IR-342		
EDF Trading North America, LLC			IR-2019	
EGP Energy Solutions, LLC d/b/a Atlantic Energy Resources		IR-1363		IR-1430
Eisenbach Consulting, LLC		IR-1950		IR-1951
Electric Advisors, Inc.		IR-1183		IR-1523
Ellicott City Investments, LLC d/b/a Allied Power Services		IR-1890		IR-1891
Emex, LLC		IR-2065		
Eneractive Solutions, LLC		IR-1939		
Energy Acceptance, Corp.		IR-2074		
Energy Advisory Service, LLC		IR-1486		IR-1485
Energy Edge Consulting, LLC		IR-2022		
Energy Enablement, LLC		IR-2385		
Energy Management Resources of Missouri, Inc.		IR-2067		IR-2073
Energy Options, LLC		IR-568		
Energy Plus Holdings, LLC	IR-1805			
Energy Plus Natural Gas, LP			IR-2216	
Energy Professionals, LLC		IR-1791		
Energy Services Management, LLC d/b/a Maryland Energy Consortium		IR-236		IR-312

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Energy Services Providers, Inc. d/b/a Maryland Gas and Electric		IR-2110		
Energy Shopper, LLC		IR-2048		
Energy Trust, LLC		IR-1682		IR-1681
Etheredge Partners, LLC		IR-2054		
Field Personnel Services d/b/a Vanguard Engineering Services		IR-1789		
FirstEnergy Solutions Corp	IR-225			
Gateway Energy Services Corporation	IR-340		IR-334	
GDF Suez Energy Resources	IR-605			
GDF Suez Retail Energy Solutions, LLC	IR-2404			
Genesis Energy International, LLC		IR-1986		
Glacial Energy of Maryland, Inc.	IR-888			
Glacial Natural Gas, Inc.			IR-1855	
Global Energy Market Services, LLC		IR-2170		
Global Montello Group Corp.		IR-2225		
Goldstar Energy Group, Inc.		IR-1370		IR-1381
Good Energy, LP		IR-1592		
Green Power Management Solutions, LLC		IR-1835		IR-1834
Hess Corporation	IR-219		IR-323	
Horizon Power & Light, LLC	IR-704			
Houston Energy Services Company, L.L.C			IR-403	
Hudson Energy Services, LLC	IR-1114		IR-1120	
I.C. Thomasson Associates, Inc.		IR-1445		IR-1446
IDT Energy, Inc.	IR-1747		IR-1745	
Integrity Energy, LTD		IR-1985		
Integrys Energy Services	IR-951			
IntelliGEN Resources LP		IR-2113		
Interstate Gas Supply, Inc. d/b/a IGS Energy	IR-2182			
Interstate Gas Supply, Inc. d/b/a IGS Energy d/b/a Columbia Retail Energy			IR-1836	
Invado International, LLC		IR-2026		IR-2025
Liberty Power Corp, LLC	IR-607			
Liberty Power Delaware, LLC	IR-962			
Liberty Power Holdings, LLC	IR-957			
Liberty Power, MD, LLC	IR-793			
Linde Energy Services	IR-753			
Long Distance Consultants, L.L.C.		IR-1455		
MABLock Consulting d/b/a The Lock Group		IR-1683		
Maglor Marketing Group		IR-2088		IR-2089
Major Energy Electric Services, LLC	IR-2098			
Major Energy Services, LLC			IR-1749	
Marathon Oil Company			IR-364	
Market Direct LLC d/b/a mdenergy		IR-614		
Maryland Energy Advisors, LLC		IR-1954		
Maryland Energy Trust, LLC		IR-1994		
MCENERGY, INC.		IR-2354		
Metromedia Energy, Inc.			IR-355	
Metromedia Power, Inc.		IR-867		
Mid Atlantic Renewables, LLC		IR-856		
MidAmerican Energy Company	IR-798			

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Mid-Atlantic Aggregation Group Independent Consortium, L.L.C. d/b/a MAAGIC		IR-234		IR-234
Mid-Atlantic Cooperative Solutions, Inc. d/b/a Aero Energy			IR-2030	
Mitchell Energy Management Services, Inc.		IR-1371		
Mondre Energy, Inc.		IR-2334		
MRDB Holdings, LP d/b/a LPB Energy Consulting		IR-930		IR-1000
Mxenergy Electric Inc.	IR-1853			
Mxenergy, Inc.			IR-327	
Nania Energy, Inc.		IR-1857		
National Power Source, LLC		IR-2084		
National Utility Service, Inc.		IR-1400		IR-1401
Natures Current, LLC		IR-1352		
Netpique, LLC		IR-2432		
NextEra Energy Services, LLC	IR-966			
Noble Americas Energy Solutions, LLC	IR-464		IR-464	
North American Power and Gas LLC	IR-1983			
North Shore Energy Consulting, LLC		IR-2160		
Northeast Energy Partners		IR-1649		
NOVEC Energy Solutions, Inc.			IR-338	
NRGing, LLC d/b/a NetGain Energy Advisors		IR-2038		IR-2037
Oasis Power, LLC d/b/a Oasis Energy	IR-1848		IR-1929	
On-Demand Energy, Inc.		IR-1442		
Open Market Energy, LLC		IR-1981		IR-2013
Palmco Energy MD, LLC			IR-1803	
Palmco Power MD, LLC	IR-1804			
Patch Energy Services, LLC		IR-1943		
Patriot Energy Group, Inc.		IR-2187		
Peninsula Energy Services Company, Inc.			IR-2003	
Pepco Energy Services, Inc.	IR-222			
Pepco Energy Services, Inc. also d.b.a. Conectiv Energy Services			IR-316	
Planet Energy (Maryland) Corp.	IR-2133		IR-2121	
Platinum Advertising II, LLC		IR-1673		IR-1668
Positive Energy Electricity Supply, LLC		IR-2164		
Power Brokers, LLC		IR-2066		
Power Brokers, LP		IR-1610		
Power Management		IR-1670		IR-1669
PPL EnergyPlus, LLC	IR-230		IR-335	
Premier Energy Group		IR-942		IR-943
Premier Power Solutions, LLC		IR-894		IR-894
Prospect Resources, Inc.		IR-2042		IR-2041
Public Power & Utility of Maryland, LLC	IR-1781			
QVINTA Energy Services		IR-557		IR-530
Reflective Energy Solutions, LLC		IR-2352		IR-2253
Reliable Power Alternatives Corp.		IR-1719		
Reliant Energy Northeast, LLC d/b/a Reliant Energy	IR-2058			
ResCom Energy, LLC	IR-2120			
Resource Energy Systems, LLC		IR-2115		

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
Richards Energy Group, Inc.		IR-818		
RMI Consulting, Inc.		IR-1685		
Satori Enterprises, Inc.		IR-1499		
Secure Energy Soltions, LLC		IR-2117		
Select Energy Partners, LLC		IR-1864		
Senergy Corporate Ventures, LLC		IR-2325		IR-2326
Shell Energy North America	IR-1357		IR-1358	
Silver Star Associates Corporation		IR-2194		
Simply Competitive Energy, LLC		IR-2304		
Smart Choice Energy Services		IR-1611		IR-1612
Smart One Energy, LLC			IR-2355	
SmartEnergy.com, Inc.	IR-270			
SourceOne, Inc. (DE)		IR-2111		IR-2172
South Jersey Energy Company	IR-740			
South River Consulting		IR-863		
SouthStar Energy Services, LLC d/b/a Maryland Energy			IR-2106	
Spark Energy Gas, LP			IR-613	
Spark Energy, LP	IR-979			
Sprague Energy Corp.				IR-339
Stand Energy Corporation			IR-632	
Starion Energy PA, Inc.	IR-2094			
Statoil Natural Gas LLC			IR-561	
Stream Energy Maryland, LLC	IR-2072			
Summit Energy Services		IR-1396		
Suncom Energy Inc.		IR-2051		
Sustainable Star LLC		IR-2306		
Taylor Consulting and Contracting, LLC		IR-1790		IR-1960
Technology Resource Solutions, Inc.				IR-2105
Technology Resources Solutions, Inc.		IR-1802		
TES Energy Services, LP		IR-2169		
Texas Energy Options, Inc.		IR-1542		
Texas Retail Energy, LLC	IR-2272			
TFS Energy Solutions, LLC		IR-918		
TFS Energy Solutions, LLC d/b/a Tradition Energy				IR-982
The Energy Link, LLC		IR-2068		IR-2069
The Eric Ryan Corporation		IR-1438		IR-1437
The Legacy Energy Group		IR-1692		IR-1691
The Loyalton Group, Inc.		IR-1766		IR-1765
Tiger Natural Gas			IR-351	
Tybec Energy Management Specialist, Inc.				IR-2299
Tybec Energy Management Specialists, Inc.		IR-2163		
U.S. Gas & Electric d/b/a Maryland Gas & Electric			IR-1744	
U.S. Harvest Postal Protection Services Corp.d/b/a United States Ethane Gas Corp.				IR-1824
U.S. Harvest Postal Protection Services Corporation d/b/a U.S. Harvest Energy & Technologies Corp.		IR-1774		
U.S. Sun Energy, Inc.		IR-1952		

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
UEC Energy, LLC		IR-1972		
UGI Energy Services, Inc.	IR-237		IR-319	
Unified Energy Services, LLC		IR-1751		
Usource, LLC		IR-1160		
UtiliTech, Inc.		IR-915		IR-915
Utility Savings Solutions		IR-2322		
Veterans Energy Supply Company, LLP		IR-2397		
Virginia Power Energy Marketing, Inc. d/b/a Dominion Sales and Marketing, Inc.			IR-689	
Viridian Energy PA, LLC	IR-1840			
Volunteer Energy Services, Inc.		IR-2012	IR-2004	
Washington Gas Energy Services, Inc.	IR-227		IR-324	
World Energy Solutions, Inc.		IR-619		IR-953
Xencom Green Energy, LLC		IR-2165		

Source: PSC database and Table A-6 in Company data responses to the Commission's 2011 data request for the Ten-Year Plan.

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 does not imply that all suppliers are offering services.

Electric Supplier	65
Electric Broker	146
Gas Supplier	57
Gas Broker	62
Total Suppliers (Incl. Brokers)*	**244**

* Certain suppliers have both natural gas and electric licenses.

Table A-7: Transmission Enhancements by Service Area

								Start location		End Location	
Transmission Owner	Voltage (kV)	Length (miles)	No. of Circuits	Start Date	Comp. Date	In-Service Date	Purpose	County	Terminal	County	Terminal
BGE	115	0.4	2	2007	2013	2013	BTR	Harford	Perryman	Harford	Harford
BGE	115	3	2	2008	2014	2014	DA	Baltimore City	Westport	Baltimore City	Wilkens
BGE	500	1	2	2009	2019	2019	BTR	Calvert	MAPP Project	Calvert	MAPP Project
BGE	230	8.6	1	2011	2014	2014	BTR	Harford	Conastone	Harford	Graceton
BGE	115	3.3	1	2010	2014	2014	BTR	Baltimore County	Deer Park	Baltimore County	Northwest
BGE	115	1	2	2009	2014	2014	BTR	Baltimore City	Orchard St	Baltimore City	Front St
BGE	115	0.6	2	2012	2014	2014	DA	Baltimore City	Coldspring	Baltimore City	Melvale
BGE	230	13.7	1	2009	2014	2014	BTR	Harford	Graceton	Harford	Bagley
BGE	115	5.2	2	2012	2015	2015	DA	Baltimore City	Erdman	Baltimore City	Argon
BGE	115	5	1	2012	2015	2015	BTR	Baltimore City	Melvale	Baltimore City	Argon
BGE	230	6.1	2	2007	2015	2015	BTR	Harford	Raphael Rd	Harford	Bagley
BGE	230	4	2	2010	2015	2015	BTR	Baltimore County	Northwest	Baltimore County	Emory Grove
BGE	230	11.7	2	2007	2019	2019	BTR	Harford	Raphael Rd	Harford	Perryman
DPL	138	24	1	2014	2015	2015	BTR	Queen Annes	Wye Mills	Queen Annes	Church

								Start location		End Location	
Transmission Owner	**Voltage (kV)**	**Length (miles)**	**No. of Circuits**	**Start Date**	**Comp. Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
DPL	69	11.7	1	2014	2016	2016	STR	Queen Annes	Wye Mills	Queen Annes	Stevensville
DPL	69	4.42	1	2015	2017	2017	STR	Wicomico	Sharptown	Dorchester	Vienna
DPL	69	2.61	1	2011	2012	2012	BTR	Worcester	Ocean Bay	Worcester	Maridel
DPL	69	18.41	1	2011	2012	2012	BTR	Dorchester	Todd	Talbot	Trappe
DPL	138	12.33	1	2011	2012	2012	BTR	Worcester	Bishop	Sussex	Indian River
DPL	139	12.33	1	2013	2014	2014	BTR	New Castle	Townsend	Queen Annes	Church
DPL	230	28.28	1	2016	2017	2017	BTR	Caroline	Steele	Dorchester	Vienna
DPL	230	18.7	1	2016	2018	2018	BTR	Somerset	Loretto	Dorchester	Vienna
DPL	230	9.51	1	2016	2019	2019	BTR	Wicomico	Piney Grove	Somerset	Loretto
DPL	69	5.99	1	2016	2020	2020	DA	Queen Annes	Grasonville	Queen Annes	Queenstown
DPL	69	5.99	1	2016	2021	2021	DA	Queen Annes	Wye Mills	Queen Annes	Queenstown
DPL	69	12	1	2013	2014	2014	DA	Kent	Lynch	Kent	McCleans
DPL	69	12	1	2013	2014	2014	DA	Kent	Chestertown	Kent	McCleans
DPL	69	6.52	1	2012	2013	2013	DA	Kent	Massey	Queen Annes	Church
DPL	69	2.25	1	2015	2016	2016	DA	Talbot	Trappe	Talbot	Lakeside
DPL	69	2.25	1	2015	2016	2016	DA	Talbot	Talbot	Talbot	Lakeside
DPL	138	3.96	1	2011	2011	2011	BTR	Accomack	Wattsville	Accomack	Oak Hall
DPL	138	5.22	1	2014	2015	2015	BTR	Cecil	Cecil	New Castle	Glasgow
DPL	138	N/A	N/A	2012	2013	2013	BTR	Worcester	138th Street	Worcester	SVC site @ 138th Street Sub.
DPL	69	19.13	1	2014	2016	2016	BTR	Accomack	Wattsville	Worcester	Kenney
DPL	69	15.04	1	2015	2014	2014	BTR	Somerset	Cristfield	Somerset	Kings Creek

								Start location		End Location	
Transmission Owner	**Voltage (kV)**	**Length (miles)**	**No. of Circuits**	**Start Date**	**Comp. Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
DPL	69	8.74	1	2016	2014	2014	BTR	Worcester	Ocean City	Worcester	Worcester
DPL	69	15.04	1	2017	2014	2014	BTR	Somerset	Cristfield	Somerset	Kings Creek
DPL	69	8.74	1	2018	2014	2014	BTR	Worcester	Ocean City	Worcester	Worcester
PE	138	16.7	1	2011	2012	2012	BTR	Preston, WV	Albright	Garrett	Mt. Zion
PE	230	3.2	1	Canc.	--	--	BTR	Frederick	Doubs	Frederick	Eastalco (Section 205)
PE	230	3.7	1	Canc.	--	--	BTR	Frederick	Doubs	Frederick	Eastalco (Section 206)
PE	138	3.2	1	2011	2012	2012	BTR	Garrett	Mt. Zion	Mineral, WV	Beryl
PE	230	9.8	1	2011	2012	2012	BTR	Washington	Ringgold	Frederick	Catoctin
PE	230	10.7	1	2011	2012	2012	BTR	Frederick	Walkersville	Frederick	Catoctin
PE	230	12.7	1	2010	2013	2013	BTR	Frederick	Catoctin	Carroll	Carroll
PE	230	5.4	1	2010	2013	2013	BTR	Frederick	Monocacy	Frederick	Walkersville
PE	138	6.1	1	2012	2013	2013	BTR	Mineral, WV	Beryl	Allegany	Black Oak
PE	230	6.7	1	2012	2013	2013	BTR	Frederick	Doubs	Frederick	Lime Kiln (Section 207)
PE	230	6.7	1	2012	2013	2013	BTR	Frederick	Doubs	Frederick	Lime Kiln (Section 231)
PE	138	4.8	1	2012	2013	2013	BTR	Berkeley, WV	Marlowe	Washington	Halfway
PE	138	0.1	2	2014	2015	2014	DA	Garrett	Altamont (new)	Garrett	Albright – Mt. Zion

								Start location		End Location	
Transmission Owner	**Voltage (kV)**	**Length (miles)**	**No. of Circuits**	**Start Date**	**Comp. Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
PE	138	4	1	2014	2015	2014	BTR	Washington	Ringgold	Franklin, PA	East Waynesboro
PE	765	19.6	1	2012	2015	SUSP	BTR	Hardy, WV	Welton Spring (new)	Frederick	Kemptown (new)
PE	230	24.9	1	2016	2017	2017	BTR	Doubs	Frederick	Frederick	Monocacy
PE	138	0.1	2	2016	2017	2017	DA	Washington	McDade (new)	Washington	Halfway – Paramount No. 1
PE	230	2.1	2	2018	2019	2019	DA	Frederick	Urbana1	Frederick	Lime Kiln - Montgomery
PE	230	0.1	2	2019	2020	2019	DA	Frederick	Jefferson No. 1 (new)	Frederick	Doubs - Monocacy
PE	230	0.1	2	2019	2019	2019	DA	Frederick	South Frederick No. 1 (new)	Frederick	Monocacy – Lime Kiln
PE	138	0.1	2	2019	2020	2020	DA	Washington	Fairplay (new)	Washington	Marlowe - Boonsboro
PE	230	0.6	2	2019	2020	2020	DA	Frederick	Ridgeville 1	Frederick	Mt. Airy - Damascus
Pepco	230	10.7	2	2009	2011	2011	BTR	Dickerson	Existing	Quince Orchard	Existing
Pepco	230	7.5	1	2010	2011	2011	BTR	Dickerson	Existing	Pleasant View	Existing
Pepco	230	Unknown	2	2011	2012	2012	BTR	Quince Orchard	Existing	Bells Mill Rd.	Existing
Pepco	230	5.34	2	2012	2012	2012	BTR	Benning	Existing	Ritchie	Existing
Pepco	230	6.42	4	2013	2012	2012	BTR	Burches Hill	Existing	Palmers Corner	Existing

								Start location		End Location	
Transmission Owner	**Voltage (kV)**	**Length (miles)**	**No. of Circuits**	**Start Date**	**Comp. Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
Pepco	230	5.01	4	2011	2013	2013	BTR	Oak Grove	Existing	Ritchie	Existing
Pepco	230	10.98	1	2012	2014	2014	BTR	Ritchie	Existing	Buzzard Point	Existing
Pepco	230	10.83	1	2012	2014	2014	BTR	Ritchie	Existing	Buzzard Point	Existing
Pepco	500	33	1	2010	2017	2017	BTR	Possum Point	Existing	Burches Hill	Existing
Pepco	500	19	1	2010	2017	2017	BTR	Burches Hill	Existing	Chalk Point	Existing
Pepco	500	20	1	2010	2017	2017	BTR	Chalk Point	Existing	Calvert Cliffs	Existing
SMECO	230	20	2	2012	2013	2013	Capacity	Calvert	Holland Cliff Sw. St.	Calvert	Sollers Wharf Sw. St.
SMECO	230	10	2	2014	2015	2015	Reliability	Calvert	Sollers Wharf Sw. St.	St. Mary's	Hewitt Rd. Sw. St.

Purpose Codes:

BTR ¾ Baseline Transmission Reliability

C ¾ Capacity

DA ¾ Distribution Adequacy

STR ¾ Supplemental Transmission Reliability

R ¾ Reliability

Source: Company data responses to Question 7 in the Commission's 2011 data request for the Ten-Year Plan.

Table A-8: Renewable Projects Providing Capacity and Energy to Maryland Customers as of December 31, 2010

Utility Service Area	Operator/Owner	Plant Name	County	Capacity Statistics (MW)		Energy Source
				Name Plate	*Summer*	
PE	BP Piney & Deep Creek LLC	Deep Creek	Garrett	20	18	Water
BGE	Constellation Solar Maryland, LLC	McCormick & Co. Inc. at Belcamp	Hartford	1.4	1.4	Solar
Pepco	Covanta Montgomery, Inc.	Montgomery County Resource Recovery	Montgomery	67.8	54	Municipal Solid Waste
PE	Criterion Power Partners LLC	Criterion Wind Project	Garrett	70	70	Wind
BGE	Eastern Landfill Gas LLC	Eastern Landfill Gas LLC	Baltimore	3	3	Landfill Gas
BGE	Energy Recovery Operations, Inc	Harford Waste to Energy Facility	Harford	1.2	1.1	Municipal Solid Waste
BGE	Exelon Power	Conowingo	Harford	506.8	572	Water
DPL	Industrial Power Generating Company LL	Wicomico	Wicomico	5.4	5.4	Landfill Gas
DPL	Maryland Environmental Service	Eastern Correctional Institute	Somerset	3.8	2.6	Wood/Wood Waste Solids
Pepco	Prince George's County	Brown Station Road Plant II	Prince Georges	6.7	5.6	Landfill Gas
Pepco	SCE Engineers	Montgomery County Oaks LFGE Plant	Montgomery	2.4	2.3	Landfill Gas
BGE	Wheelabrator Environmental Systems	Wheelabrator Baltimore Refuse	Baltimore City	64.5	61.3	Municipal Solid Waste
Choptank	Worcester County Renewable Energy LL	Worcester County Renewable Energy	Worcester	2	2	Landfill Gas
			TOTAL	**755**	**798.7**	

Source: *Report EIA-860: "GenY10" Excel*, U.S. ENERGY INFORMATION ADMINISTRATION, (Nov. 30, 2011), *available at*: http://38.96.246.204/cneaf/electricity/page/eia860.html.

Table A-9: Power Plants in the PJM Process for New Electric Generating Stations in Maryland as of December 31, 2010

Electric Company Service Territory	PJM Queue #	Project Name	Status of Application (12/31/10)	Plant Capacity (MW)	Fuel Type	Projected In-Service Date
BGE	S32	Perryman	Suspended	256	natural gas	2014 Q2
BGE	V1-033	Pumphrey 115kV	Under Construction	132	other	2015 Q1
BGE	V3-037	Naval Academy Junction 13kV	Under Construction	3	natural gas	2013 Q2
BGE	V4-038	Friendship Manor 34.5kV	Under Construction	1	methane	2013 Q1
BGE	W1-033	Pumphrey 115kV	Under Construction	157	biomass	2015 Q1
BGE	W4-030	Jessup	Under Construction	0	solar	2012 Q1
DPL	T144	Pocomoke	Under Study	20	biomass	2010 Q1
DPL	U3-003	Mt. Olive 69kV	Under Construction	2	methane	2012 Q2
DPL	U3-004	Cecil	Under Study	2	methane	2009 Q3
DPL	V2-028	Vienna	Under Study	6	solar	2010 Q4
DPL	W1-070	Laurel 69kV	Under Study	20	solar	2011 Q2
DPL	W3-071	Worcester 25kV	Under Study	13	solar	2012 Q2
DPL	W3-160	Worcester 25kV	Under Study	10	solar	2011 Q1
DPL	W4-017	Kings Creek-Crisfield 69kV	Under Study	100	wind	2013 Q4
DPL	X1-032	Costen 25kV	Under Construction	4	solar	2012 Q2
DPL	X1-096	Loretto-Kings Creek 138kV	Under Study	150	wind	2014 Q4
DPL	X2-045	Kenney-Mt. Olive 69kV	Under Study	20	solar	2013 Q2
DPL	X2-084	East New Market 69kV	Under Study	20	solar	2012 Q4
DPL	X3-008	Todd 69kV	Under Study	20	solar	2017 Q2
DPL	X3-009	New Market 69kV	Under Study	20	solar	2017 Q2
DPL	X3-015	West Cambridge-Vienna 69kV	Under Study	20	solar	2012 Q4
DPL	X3-066	Church Hill 69kV	Under Study	7	solar	2012 Q3
DPL	X3-067	Church Hill 12kV	Under Study	2	solar	2012 Q3
DPL	X3-073	Massey 69kV	Under Study	10	solar	2013 Q1
DPL	X3-074	Chestertown 69kV	Under Study	12	solar	2013 Q1
DPL	X4-017	Fruitland 69kV	Under Study	20	solar	2017 Q2
PE	S14	Dans Mountain	Under Study	70	wind	2009 Q4
PE	T16	Gorman-Snowy Creek 69kV	Under Study	30	wind	2011 Q4
PE	U2-030	Four Mile Ridge Wind 138kV	Under Study	60	wind	2010 Q4
PE	U4-007	Jennings Randolph Dam	Under Study	14	hydro	2013 Q3
PE	W1-116	Emmitsburg 34kV	Under Construction	14	solar	2012 Q2
PE	W3-070	Metropolitan Court 34.5kV	Under Study	52	biomass	2013 Q4
PE	W4-102	Lappans 34.5kV	Under Study	17	solar	2012 Q4
PE	X2-038	Halfway 12.5kV	Under Study	2	methane	2012 Q3
PEPCO	S17	Talbert 230kV	Suspended	225	natural gas	2017 Q4
PEPCO	T133	Chalk Point-Bowie 230kV	Suspended	225	natural gas	2016 Q4
PEPCO	T134	Chalk Point-Bowie 230kV	Suspended	325	natural gas	2017 Q4
PEPCO	V3-017	Morgantown-Oak Grove	Under Study	725	natural gas	2012 Q2
PEPCO	W3-105	Dickerson 230kV	Under Construction	18	oil	2011 Q4
PEPCO	W4-010	White Oak	Under Study	53	natural gas	2014 Q1
PEPCO	W4-020	Mt. Zion 13.8kV	Under Study	10	solar	2011 Q3
PEPCO	W4-044	Kelson Ridge 230kV	Under Study	1450	natural gas	2014 Q2
PEPCO	X2-030	Morgantown-Oak Grove 230kV	Under Study	830	natural gas	2016 Q1
PEPCO	X3-087	Burches Hill-Brandywine 230kV	Under Study	914	natural gas	2016 Q2

Electric Company Service Territory	PJM Queue #	Project Name	Status of Application (12/31/10)	Plant Capacity (MW)	Fuel Type	Projected In-Service Date
PEPCO	X3-088	Dickerson 230kV	Under Study	440	natural gas	2016 Q4
PEPCO	X3-102	Burches Hill-Possum Point 500kV	Under Study	971	natural gas	2016 Q2
PEPCO	X4-006	Kelson Ridge 230kV	Under Study	785	natural gas	2015 Q2
PEPCO	X4-007	Kelson Ridge 230kV	Under Study	785	natural gas	2015 Q2
PEPCO	X4-026	Aquasco 230kV	Under Study	792	natural gas	2015 Q2
SMECO	V2-042	Calvert Cliffs 500kV	Under Study	1640	nuclear	2017 Q2
			Total (MW):	**11,474**		

Source: *Generation Queues: Active*, PJM, http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx (last visited December 18, 2011).