Appendix A – Permits and Approvals That May Be Required for a Power Plant in Maryland

Under Maryland regulations, most of the air quality permits and approvals that power plants in Maryland are required to obtain to construct new power plants or modify existing power plants are incorporated into the Certificate of Public Convenience and Necessity (CPCN). For example, air quality Permits to Construct for minor power plant sources and Prevention of Significant Deterioration (PSD) permits for new major power plant sources in Maryland are part of the CPCN. As with all major source permits issued by the State, the U.S. Environmental Protection Agency (EPA) Region III is provided the opportunity to review and comment on the draft licensing conditions during the CPCN process. Certain required permits, most notably the Clean Air Act Title IV Acid Rain Program permits, are issued separately by EPA; however, the State does incorporate Acid Rain Program requirements into the CPCN.

On the other hand, several of the permits and approvals that power plants and transmission lines need to operate in Maryland are issued and enforced by the Maryland Department of the Environment (MDE). For example, facility-wide Title V Operating Permits are administered by MDE.

The CPCN also encompasses the water appropriation permitting process for a new power plant. Obtaining a CPCN grants a facility developer the right to withdraw ground water and surface water, subject to relevant permit conditions that are incorporated into the CPCN (such as flow monitoring and reporting).

The table below lists the permits and approvals that may be required for a new power plant or transmission line in Maryland. The highlighted rows indicate those permits that are included within the CPCN. While there are several permits that are issued separately from the CPCN, PPRP evaluates the entire suite of environmental and socioeconomic impacts during the consolidated licensing review process (described in Chapter 1 of this report). It should also be noted that the CPCN process supersedes local zoning requirements. PPRP considers land use compatibility and zoning designations as part of the overall project evaluation; however, an applicant does not need to obtain formal zoning approval from the local planning authority.

List of Permits and Approvals Typically Required for Construction and Operation of Power Plants in Maryland

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
CPCN	Certificate of Public Convenience and Necessity	Maryland Public Service Commission (PSC)	Incorporates several State and federal permits and approvals — those incorporated into CPCN are highlighted
AIR QUALITY			
Air Quality Permit to Construct	Applies to any minor new, modified, or reconstructed sources of air pollution	PSC/Maryland Department of the Environment (MDE)	Constitutes "minor NSR construction permit", see PUC 7-208
Nonattainment Area New Source Review (NA-NSR)	Required for new or modified major sources that emit VOCs or NOx; requirements and limitations are location-specific	PSC/MDE	Requires Lowest Achievable Emission Rate (LAER), offsets, and alternatives analyses, see PUC 7-208
Prevention of Significant Deterioration (PSD)	Required for major new or modified sources in attainment areas with potential emissions over 100 tons per year	PSC/MDE	Requires air quality monitoring, Best Achievable Control Technology (BACT), ambient impact analyses (modeling), impact on surrounding Class I areas, see PUC 7-208
Title V Operating Permit (federal) and Maryland Permit to Operate	Facility-wide permit to operate	MDE	Title V operating permit application may be filed in conjunction with CPCN, see EN 2-405
Title IV - Acid Rain Permit	Covers "affected" power plant generating units for minor SO_2 emissions	MDE	Requires continuous emission monitoring, recording, and reporting; acquisition of SO_2 allowances
Clean Air Act Section 112(r)	Risk management plan for storage of ammonia and other toxic substances, as listed	EPA	May apply to facilities that use ammonia in SCR systems to control NO_x
Clean Air Interstate Rule (CAIR)	The rule uses a cap and trade system to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x) by 70 percent.	MDE	Applies to 28 eastern states and the District of Columbia
WATER QUALITY AND USE			
Waterway Construction	Applies to construction within State wetlands and waterways	MDE/USACE	Wetland impact determination necessary
Maryland Coastal Zone Management Program	Balances development and protection in the coastal zone, which includes the Chesapeake Bay, coastal bays, and Atlantic Ocean, as well as the towns, cities and counties that contain/help govern the coastline	MDE/NOAA	State and federally coordinated program
Chesapeake Bay Critical Areas Act	Protects MD's Critical Areas, which is all land within 1,000 feet of the Mean High Water Line of tidal waters or the landward edge of tidal wetlands and all waters of and lands under the Chesapeake Bay and its tributaries.	DNR/County/ Municipality	Enforced at the local or county level
Erosion/Sediment Control Plan Approval	Plan to prevent erosion and stormwater pollution during construction	County	Required before construction disturbing 5,000+ square feet of area
Storm Water Management Plan	Plan to prevent storm water pollution associated with industrial activities.	County	Required prior to discharging storm water associated with industrial activity
Surface Water Discharge/ NPDES Permit	Combined state and federal permit for industrial wastewater and possibly storm water discharge to state waters. Must meet applicable federal effluent guidelines, satisfy state water quality standards, and comply with Section 316(b) regulations regarding surface withdrawals	MDE	Individual NPDES permits may include discharge of storm water associated with industrial activities. If not, facility must apply for a general permit for these activities. The permit application is due 180 days before discharge commences.

Note: Grey highlighted rows indicate those permits and approvals that are incorporated into the CPCN.

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
General Storm Water Permit (Industrial Activity)	For discharges associated with industrial activity	MDE/County Conservation District	MDE determines whether a facility can operate under a general storm water permit.
Wellhead Protection Program	Groundwater protection	MDE/County/ Municipality	Applies to public water supply wells and wells in groundwater management areas
Water and Sewerage Conveyance and Construction Permit	Required before installing, extending or modifying community water supply and/or sewerage systems including treatment plants, pumping stations and major water mains and sanitary sewers	POTW or County/ Municipality	Required to ensure that infrastructure projects throughout the State are designed on sound engineering principles and comply with State design guidelines to protect water quality and public health.
Dam and Reservoir Safety Permit	If applicable, for any lake or pond used for non-process water	MDE/USACE	640 acre drainage area, 20 foot or greater embankment, high hazard class, natural trout water
Maryland Water Quality Certification	CWA Section 401, for construction in wetlands	MDE	Wetland impact determination necessary
Surface Water Withdrawal Permit/Water Appropriation & Use Permit	Water Appropriation and Use is tracked by a Water Resources Administration Permit	PSC/MDE	The appropriation of either surface or groundwater is incorporated into the CPCN. Trigger: withdrawal exceeding 10,000 gallons per day.
Public Water Supply Line Connection	A variety of Clean Water Act permits, SHPO clearance, NRCS consultation, floodplain permitting, and road boring permits	County/ Municipality	
Tidal Wetland Permit	Joint state-federal review and permitting for tidal wetland impacts	PSC/MDE Water Management Administration (WMA)/USACE	Wetland impact determination necessary
Non-Tidal Wetlands Permit	Joint state-federal review and permitting for non-tidal wetland impacts	MDE WMA/ USACE	Wetland impact determination necessary
Groundwater Withdrawal	Required for any groundwater withdrawal	PSC/MDE	Requires submittal of application to Water Management Administration for any withdrawal of groundwater for use in project (sanitary water, process water, cooling, etc…). Also have to conduct impact assessment.
Consumptive Use Review and Approval Process	Required for new consumptive water uses in the Susquehanna River basin	Susquehanna River Basin Commission	Requires approval by Commission for any new consumptive water uses or if consumptive use exce eds an average of 20,000 gallons per day for any consecutive 30-day period
OTHER APPROVALS AND NOTIFICATIONS			
Facility Response Plan	For oil pollution prevention	EPA	All owners/operators of non-transportation related onshore facilities with greater than 1,000 gallons of oil on-site and the potential to discharge oil into navigable waters must prepare and submit plan
Sanitary Sewer Permit/ Industrial User's Permit	For plant sanitary or process waste disposal to municipal facilities, a WWTP Permit must be obtained from the Publicly Owned Treatment Works (POTW)	Municipal Authorities	
Health Department Permit	If septic tanks are used for sanitary waste, a Health Department Permit must be obtained	County	
Spill Prevention Control and Countermeasure (SPCC)/Storage tank regulations	Plan to prevent and manage accidental spills of petroleum products stored on site	MDE	Typical threshold quantities of petroleum products: 1,320 total above ground gallons (for tanks 55 gallons or greater), and 4,200 gallons underground

Note: Grey highlighted rows indicate those permits and approvals that are incorporated into the CPCN.

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Oil Operations Permit	State permit required for the operation of oil storage tanks	MDE	Required for storage of 10,000+ gallons of oil in above-ground tanks, transportation of oil, or operation of oil transfer facilities
Local building permits during construction	Requirements under local ordinances to be filed as necessary with County	County/ Municipality	Includes building permit and zoning and site plan approvals as applicable
Forest Conservation Act	Requirements to prepare Forest Stand Delineations and Forest Conservation Plans	DNR	
Phase II Cultural Resources Investigation	Research potential significant impacts to cultural resources on site	MHT	Coordinate with MD State Historic Preservation Officer if necessary
National Historic Preservation Act/ MD Historical Trust Act	Protection of cultural/historic artifacts found during development	MHT	Coordinate with MD State Historic Preservation Officer if necessary
Threatened and Endangered Species Clearance	State-implemented program under the Endangered Species Act; includes field investigations and data research	DNR Heritage and Biodiversity Conservation Programs	Coordinate with US Fish & Wildlife Service and NOAA
Stack or Turbine Height Notification (FAA)	Notify Federal Aviation Administration (FAA) of stack or turbine height	FAA	200 feet above ground level and higher stacks or wind turbine structures
Oversize Equipment Delivery Permit	For delivery of oversize and/or super loads of construction equipment from rail to site	Maryland Department of Transportation (MDOT)	Threshold (only 1 needs to be exceeded to trigger permit) 16 ft. wide, 16 ft. high, 150 ft. overall length, 132,000 lb. weight
New Roadway Access Permit	To cover new road to plant	MDOT	Letter of request, location sketch, overall site plan, scaled drawings, grading and drainage plan, entrance plan and method of restoring disturbed land
Solid Waste Disposal Permit for Construction and Demolition Debris	For removal and disposal of solid waste during construction	MDE/County/ Municipality	If waste is taken off site, it must be taken to a properly permitted facility
Utility Occupancy of SHA-owned Land	For projects that are proposed for location on property owned by SHA.	State Highway Administration (SHA)	
Approval for Solid Waste Disposal	If waste, such as fly ash, is taken off-site, it must be taken to a properly permitted facility	MDE	
Notification of Regulated Waste Activity	For waste oil, universal waste, hazardous waste, disposal registration, RCRA modification	MDE	If facility wishes to haul its own regulated waste, an additional permit may be necessary
Notice of Proposed Construction or Alteration	For projects located near an airport or landing strip	FAA, MDOT	Required if proximity to airport or landing strip within 1 mile of any portion of the proposed route
PCB Registration	Covers disposal of electrical transformers that previously contained PCBs which are proposed to be disposed at a Class I or II residual waste landfill	EPA	Thresholds are 50 to 500 ppm PCBs for transformers and other PCB-containing wastes
National Environmental Policy Act (NEPA)	Completion of an Environmental Assessment (EA) or Environmental Impact Statement (EIS)	Federal entity, such as USACE or NPS	Triggered when project crosses federal lands

Note: Grey highlighted rows indicate those permits and approvals that are incorporated into the CPCN.

Appendix B – Electricity Markets and Retail Competition

Introduction

Effective July 2000, the Maryland Electric Customer Choice and Competition Act of 1999 restructured the electric utility industry to allow Maryland businesses and residents to shop for power from suppliers other than their franchised electric utilities. Prior to restructuring, the local electric utility, operating as a regulated, franchised monopoly, supplied electricity to all end-use customers within its franchised service area under bundled service rates. These rates included the three principal components of electric power service: generation, transmission, and distribution. Under retail competition, electricity suppliers purchase electricity on the wholesale market for resale to electricity consumers. Consumers may choose any supplier with a license to sell electricity in Maryland. Those consumers who do not select a supplier or are unable to receive service from a competitive supplier are provided with electricity service by their regulated utility, which contracts with wholesale suppliers on behalf of its consumers, under the supervision and guidance of the Maryland Public Service Commission. This appendix provides a background on electricity markets and the influence of markets, technology, fuel, and environmental regulations on the retail prices paid by end-use consumers.

Wholesale Markets and PJM

The majority of electricity sales and purchases that occur in the wholesale market of the PJM Regional Transmission Organization are bilateral transactions, where two entities negotiate a contract for the sale and purchase of electricity according to the terms established in a contract. These bilateral contracts may be the result of a competitive solicitation or a privately negotiated power purchase agreement, the details of which are typically kept confidential. Entities seeking to buy and/or sell electricity might also look to one or more of the regional markets and trading platforms. Electricity trades can be categorized according to two main classes: physical trading and financial trading. In physical trading, the electricity supply is balanced against demand and price is established at the point where the highest offer for electricity (supply) meets the lowest bid for electricity (demand) so that the load requirements are met. Physical trades can be determined in advance of trading (e.g., participation in day-ahead markets) or after trading (e.g., imbalance markets and ancillary services).[1]

The primary purpose of financial trading is to protect against expected price volatility and provide price discovery for purposes of evaluating future supply contracts. However, power marketers and traders can also use electricity futures contracts to obtain physical electricity at the hub. This delivery potential helps to validate the futures prices. Financial trading is conducted through a financial market or exchange such as the Intercontinental Exchange, the New York Mercantile Exchange, or Chicago Board of Trade according to the specifications determined by the commodity exchange.

[1] The term "ancillary services" refers to a suite of services necessary for the reliable generation and delivery of power and includes such services as reactive supply and voltage control, scheduling, and operating reserves. A more detailed discussion of ancillary services is provided later in this appendix.

The electricity supply markets in PJM's wholesale electric market consist of four separately organized units, defined in greater detail below: two markets for the sale or purchase of energy (the Day-Ahead and Real-Time Markets); and two markets designed to support the various services required to keep the electricity system functioning (the Capacity Market and the Ancillary Services Markets). These markets are competitive and suppliers and buyers submit bids and offers. The prices for electricity, capacity, and ancillary services are set through the balancing of supply and demand. The four different wholesale markets are discussed in detail below.

Markets for Energy

Two separate PJM markets exist for the daily buying and selling of electricity. These are the Day-Ahead Market and the Real-Time Market. These markets operate on the basis of locational marginal prices (LMPs)—electricity prices that vary by time and geographic location. Sellers include those entities offering electricity supply such as generation companies, agents who may have contracts with generators, curtailment service providers (or demand response providers) who offer to reduce load on demand (a form of negative supply that serves to balance supply and demand as effectively as additional generation), and brokers. Buyers consist of those needing electricity, which can include brokers and companies termed "load serving entities" (LSEs). A load serving entity is any supplier, including regulated utilities providing standard offer service or default service, that is responsible for the sale of electricity to a retail customer. Along with electricity, LSEs must also purchase their proportionate share of the PJM system's peak capacity (to ensure reliability) and transmission services (to move the electricity from the generator to the distribution system).

Day-Ahead Market

The Day-Ahead Market is a spot market (deliveries are expected in a month or less at that day's quoted price) in which participants can purchase and sell energy for the next operating day. It provides the opportunity to request short-term energy and transmission services to meet electricity needs. Hourly LMPs are calculated by PJM for the next operating day based on generation offers and demand bids. PJM then matches bids and offers and sets the price for the Day-Ahead Market, creating a financially binding day-ahead schedule based on the known electric deliveries and corresponding hourly prices for a specific hour and location.

Each supplier in PJM submits hourly supply schedules specifying the amounts of generation at various prices it would be willing to supply. PJM arrays these bids from lowest to highest price, adjusting each price to reflect incremental system losses. Incremental losses are specific to each generation bus and reflect the impact on total system losses of an increase in generation. The price bid submitted by the last generating unit required to meet demand (the marginal unit) becomes the hourly dispatch rate. PJM then computes hourly LMPs by adjusting dispatch rates to include the effect of congestion. Congestion is also location-specific and reflects the manner in which PJM must resolve transmission constraints to serve load at various locations on the grid. If the transmission interface with PJM West is constrained, for example, PJM may have to order the dispatch of generating units elsewhere in PJM, out of economic merit order, in order to supply load in the east.

Real-Time Energy Market

The Real-Time Market acts as the balancing market between what was scheduled through the Day-Ahead Market and bilateral transactions, and what is required to meet real-time energy needs. This is a spot market where LMPs for each zone are calculated at five-minute intervals based on actual electricity grid operating conditions. Transactions are settled hourly. LSEs pay the real-time LMP for any demand that exceeds their day-ahead scheduled quantities. In cases where an LSE uses less energy than it purchased in the day-ahead market, the LSE can sell that excess energy back into the real-time market and receive revenues for it. Generators are paid real-time LMP for any generation that exceeds their day-ahead scheduled quantities as it gets sold at the real-time price into the market. Generators also must pay the real-time LMP for generation deviations below their scheduled quantities as the electricity they had promised to supply must now be supplied by other generators who need to be compensated. PJM tracks the supply and demand of each market participant and assigns costs and revenues accordingly, on an hourly basis.

Capacity Market

Capacity refers to the amount of electricity generation available at any given time. The capacity market is a forward market where LSEs purchase supply-side and demand-side capacity resources. Each LSE is required to have available its share of the PJM system peak plus a reserve margin of an additional 15 percent of peak load. This means that the system as a whole must always have more generation capacity available than what is expected to be required to meet peak loads so that extra electricity generation can be brought into use if needed, e.g., in the event of an unplanned outage of one or more large generating plants or extreme weather conditions. LSEs can acquire capacity in one of several ways, including procuring generating resources (either through construction or purchase), purchasing capacity under a bilateral agreement, or participation in the PJM capacity market.

The current PJM capacity market is based on PJM's Reliability Pricing Model (RPM), and was implemented in 2007 as a means to provide power plant developers with price signals to influence decisions on whether (and where) to construct new power plants and to provide owners of existing generation with price signals to influence decisions on whether to retire existing plants. Prior to development of the RPM, PJM contended, and many agreed, that the PJM market for generating capacity was not performing adequately, and that the market prices for capacity were too low to provide incentives for new power plant development. Additionally, the pre-RPM capacity market was highly susceptible to market manipulation, provided no mechanism for capacity payments for load response and demand-side management, resulted in uniform capacity prices throughout PJM, and only provided capacity prices out one year.

The RPM is an approach developed by PJM and used to provide a market price for capacity that is aligned with PJM's assessment of the cost of new entry, i.e., the level of revenue that a power plant developer would require to make the decision to develop peaking resources economically feasible. The approach also recognizes and accommodates higher capacity prices when PJM is capacity short and lower prices when excess capacity exists.

How the RPM Works

Fundamentally, the market clearing price is determined through the intersection of a demand curve and a supply curve.

The Demand Curve – the downward sloping demand curve, referred to by PJM as the Variable Resource Requirement (VRR), is developed for the PJM region and also for the locational delivery areas (LDAs).[2] This curve is plotted on a graph with dollars per MW-day on the vertical axis and MW of capacity (or percentage of reliability requirement) on the horizontal axis.

The Supply Curve – the supply curve is obtained by PJM through the capacity bids offered by the capacity owners. Eligible capacity includes existing and new capacity, demand-side resources (e.g., load response), and qualified transmission upgrades. The capacity offers

[2] PJM divides the PJM region into delivery areas based on transmission connections and constraints.

from the auction are stacked (lowest cost to highest cost), resulting in an upward sloping supply curve. The auction clearing price is determined by the intersection of the VRR and the supply curve (the auction bids).

PJM conducts a Base Residual Auction (BRA) to obtain committed capacity for LSEs that have not entered into bilateral contracts with capacity owners, do not own generation capacity, and have not opted for the Firm Resource Requirement (FRR) alternative.[3] The BRA is conducted three years in advance of the year for which the capacity will be committed (e.g., the BRA for the planning year June 2012 through May 2013 was held in May 2009). The BRA process determines the market clearing quantity and price for capacity for PJM as a whole and for each LDA based on the intersection of the demand curve and supply curve. The capacity resources that clear the BRA receive the market-clearing price and assume the obligation to provide capacity in the relevant planning year. Failure to satisfy that obligation entails significant penalties.

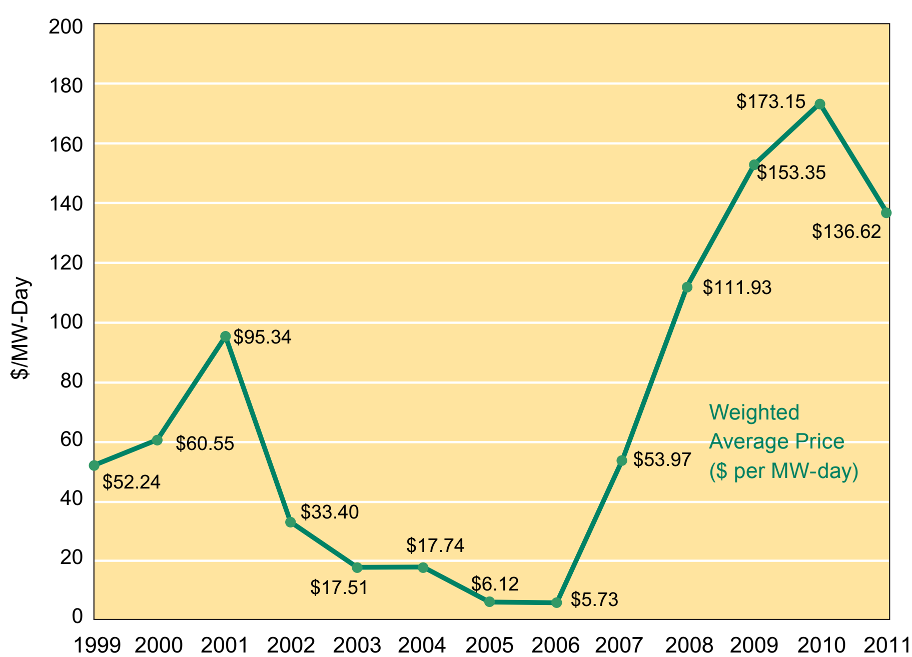
PJM may conduct "incremental auctions" following the BRA. The purpose of the incremental auctions is to allow cleared resources in the BRA to adjust the capacity quantities bid (for example, for planned resources that may not become available in the quantities expected or for unanticipated additional quantities). Additionally, PJM can use the incremental auction option to secure additional capacity if the peak load forecast is increased.

Since the introduction of the RPM capacity market, the price for capacity has increased significantly throughout the PJM region. Figure B-1 shows historic capacity prices along with RPM prices out to 2011 arising from the PJM auctions.

Ancillary Services Market

Ancillary services are all the services necessary to support the transfer of energy from generation resources to end-users or load, while maintaining the integrity of the transmission system. Ancillary services include: scheduling, system control, and dispatch; reactive supply and voltage control; regulation and frequency response; energy imbalance; and operating reserves. Costs for ancillary services are recovered from a combination of market-based and cost-based pricing cleared or set by PJM. Market-based services set prices through auctions, such as generators bidding to offer regulation and/or reserve energy. Cost-based services are provided by PJM and billed to participants according to a set rate based on revenue requirements.

Figure B-1 Average Annual PJM Capacity Prices



Source: Monitoring Analytics, "2008 State of the Market Report for PJM," March 11, 2009.

An important element of PJM's ancillary services is energy regula-

[3] Certain LSEs (utilities, electric cooperatives, or municipal utilities) may opt to commit capacity to meet peak demand plus the reserve requirement on a firm basis for a minimum five-year period and subject to PJM approval.

tion. Regulation service matches generation with short-term changes in load, maintaining desired frequency and voltage by increasing or decreasing the output of selected generators as needed via automated control signals. Longer-term deviations from scheduled load are met by the reserves and generator responses to economic signals. The regulation requirement is set daily and is equal to 1 percent of the forecast peak load. Generation or load response unit owners enter an offer price for the day and if called upon are paid the current daily price for either generation or load reduction.

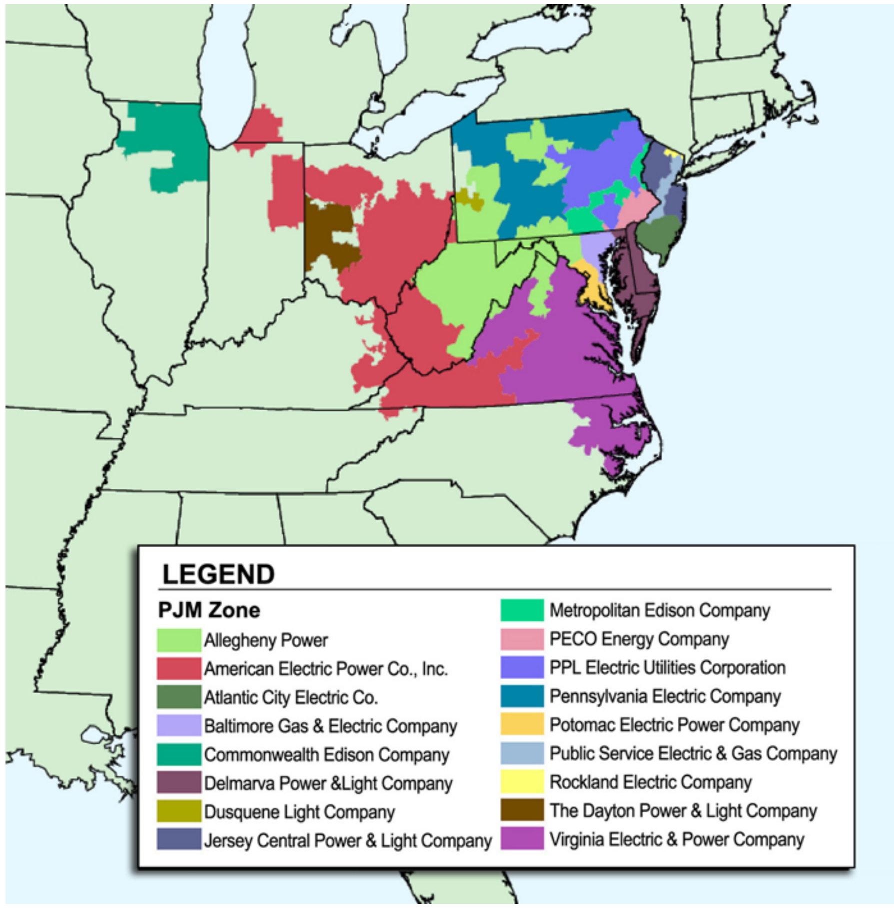
Reserves represent the generating capability that is standing by ready for service in the event of a disruption on the power system, such as the loss of a generator. These operating reserves, the standby generation made available to serve load in case there is an unplanned event, are not the same as the 15 percent reserve requirement, which is an annual capacity obligation based on the average of the five highest seasonal peaks. The 15 percent annual reserve requirement refers to the overall amount of extra capacity that must be maintained in the PJM system as a whole in order to maintain a specified level of reliability. In other words, the PJM system must always maintain a condition where overall generation ability exceeds overall electricity use by 15 percent. The operating reserves refer to the amount of generation kept in standby mode so it can be called upon in case of an emergency, such as a major unit tripping offline. Reserves can include both supply-side resources, i.e., power plants, and demand-side resources such as end-users participating in load management or load curtailment programs who can quickly reduce the amount of electricity they are using when called to do so. Primary reserves are those resources available within 10 minutes of a request by PJM. Secondary reserves must be available within 30 minutes of a request. Synchronized or spinning reserves are typically the first primary resources called upon and are paid to be available, whether called upon to respond to an event or not. These are the reserve units that are either already running but idling in standby mode, or can be started up very quickly and synchronized with the grid, and can therefore supply energy within the 10 minute timeframe.

Market Pricing

Factors Affecting Locational Marginal Prices

The PJM region is divided into several different zones (shown in Figure B-2) organized primarily according to the service territories of the distribution utilities. PJM tracks the demand and supply of electricity within each zone. The spot market price of electricity is based on the supply and demand for electricity for that time of day in that area. Depending upon local conditions, the price for electricity can be very different from zone to zone for the same time of the day. The disparity of prices from zone to zone is largely attributable to the ability, or inability, to transmit electricity from one zone to another. The transfer of electricity between zones is sometimes limited by the size or capacity of the transmission system. For a system not constrained by transmission grid limitations, conditions in all zones would be the same at all times and the marginal prices would be equal in all areas at any given time. However, in the wholesale electricity market, LMPs vary because of physical system limitations, congestion, and loss factors. This transmission congestion can have a significant impact on the price of electricity in the wholesale markets. Generators selling electricity in a zone with transmission congestion may be able to obtain higher prices than a generator with comparable operating costs located in a zone that is not subject to transmission congestion.

Figure B-2 PJM Zones



LMPs, as established at each zone, can be summarized according to time of day; peak hours are Monday through Friday (except holidays) from 7:00 am to 11:00 p.m., off-peak are the remaining evening, weekend, and holiday hours. Table B-1 provides the PJM average and median prices experienced over the 2008 calendar year.

Operating costs and other factors contribute to the bid prices offered by generators and the resulting overall annual average LMP. Fuel costs make up the largest share of generator operating costs and therefore contribute most to the bid price and hence LMP (see Figure B-3). The PJM Market Monitor calculates the factors contributing to annual average LMP based on the weighted average of the factors influencing the generator bid prices at specific locations. This weighted average considers both on- and off-peak prices, and which plants are operating on the margin in which conditions. In 2008, the capital and fuel supply costs of coal-fired generators made up 37 percent of the annual average LMP, while gas-fired generators made up 51 percent. Gas-fired generators are higher priced units, operating on the margin during peak periods, and therefore, contribute more to the average LMP.

Table B-1 PJM Off-Peak and On-Peak Simple Average LMP for 2008

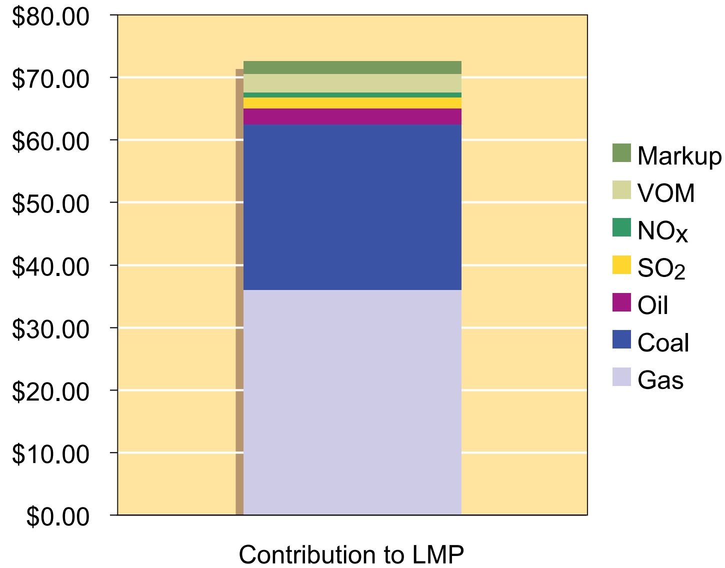
	Day Ahead		Real Time	
	Off Peak ($/MW)	On Peak ($/MW)	Off Peak ($/MW)	On Peak ($/MW)
Average	$53.11	$81.00	$53.76	$80.87
Median	$46.92	$73.92	$43.38	$70.81

In addition to fuel costs, other factors contributing to price levels include environmental costs, non-fuel operating costs, and profit margins. All generators are paid the LMP in their zone; the PJM Market Monitor calculates these factors for information purposes only.

Average annual LMPs have been rising since the late 1990s, more than doubling from 1998 to 2008 (see Table B-2). During this period, a large portion of the constructed new generating capacity has been natural gas-fired. Natural gas and petroleum prices have tripled between 1998 and 2008, due to the nature of the commodity markets and short-term supply contracts, these price increases were quickly reflected in electricity generation bid prices. Figure B-4 depicts fuel costs for electricity suppliers between 1996 and 2008. Natural gas prices have declined significantly between 2008 and 2009, and this decline in the cost of natural gas has put downward pressure on the market prices for electric power.

The cost of uranium fuel (not shown in Figure B-4) is only a small part of the overall operating and maintenance cost for a nuclear facility. However, the price of uranium has increased significantly over the last decade, rising from $12.14 per pound in 1998 to $45.88 per pound in 2008. A pound of uranium provides approximately 171 MMBtu, therefore, the cost to the electric power industry was approximately 27 cents per MMBtu in 2008.

Figure B-3 Components of Load Weighted Annual Average LMP (2008)



Note: Miscellaneous components contribute -$1.46 to LMP, which equates to -2.1 percent of the total contribution.

Table B-2 PJM Load-Weighted Average LMP

Year	LMP per MWh	Change from Previous Year	Percent Change
1998	24.16	NA	NA
1999	34.07	9.91	41.0%
2000	30.72	($3.35)	(9.8%)
2001	36.65	$5.93	19.3%
2002	31.58	($5.07)	(13.8%)
2003	41.23	$9.65	30.6%
2004	42.87	$1.64	4.0%
2005	62.50	$19.63	45.8%
2006	51.33	($11.17)	(17.9%)
2007	57.88	$6.55	12.8%
2008	70.25	$12.37	21.4%

Source: PJM, 2006 State of the Market Report (years 1998 to 2003) and Monitoring Analytics, "2008 State of the Market Report for PJM" (years 2004 to 2008).

The dispatcher must at all times respect the physical limitations of the transmission system, including thermal limits, voltage limits, and the need for the system to maintain equilibrium. These limitations sometimes prevent the use of the next least-cost generator, instead causing the dispatch of a higher-cost generator located closer to the load in lieu of a lower-cost generator located at a greater distance from the load. LMP differentials caused by transmission system limitations between zones are referred to as congestion. The PJM system is divided into three regions — Western, Mid-Atlantic, and Southern Regions. LMP differentials between regions are mainly due to congestion between the Western Region, where abundant low-cost generation is located, and the Mid-Atlantic Region, in which the major load centers are located, which can lead to significantly different electricity prices in the states that comprise PJM (see Table B-3). Additional information on congestion is provided in Chapter 2 of this CEIR.

Figure B-4 Fuel Costs for the Electric Power Industry

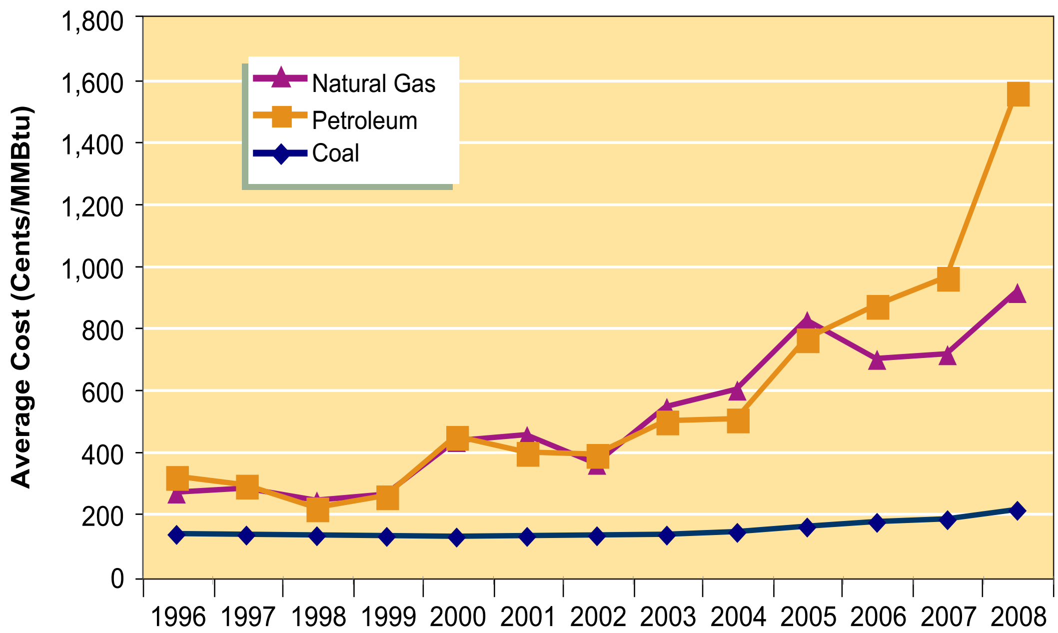


Table B-3 Real-Time Annual Load-Weighted Average LMP for 2008

State	LMP
Delaware	$82.25
Illinois	$53.63
Indiana	$55.98
Kentucky	$57.45
Maryland	$87.10
Michigan	$58.07
New Jersey	$86.48
North Carolina	$80.28
Ohio	$55.90
Pennsylvania	$73.29
Tennessee	$56.67
Virginia	$79.65
West Virginia	$58.21
District of Columbia	$86.68

Source: Monitoring Analytics, "2008 State of the Market Report for PJM," March 11, 2009.

Appendix C – Forecasting Electricity Load Growth in Maryland

Introduction

From the early 1980s through the enactment of Maryland's Electric Customer Choice and Competition Act of 1999, the Power Plant Research Program (PPRP) undertook the development of independent, long-range forecasts of electric energy sales and peak demands for each of the four investor-owned electric utilities that operated in the state. With the enactment of competitive restructuring, Maryland's traditional electric utilities no longer had the responsibility of ensuring adequate electricity generation in their respective service areas. As a consequence, developing independent forecasts of electric energy sales and peak demands on a utility-by-utility basis no longer served the purpose of allowing an independent assessment of utility planning to meet future power supply requirements. To accommodate the new electric utility industry structure, PPRP modified its forecasting to take instead a statewide approach to forecasting demand.

In the last few years, the ability of the market to deliver adequate capacity resources and the lack of any centralized resource planning has prompted regulators to institute regional resource planning requirements for utilities and regional transmission operators. In Maryland, the PJM Interconnection is the regional transmission operator and is now responsible for conducting regional transmission planning. As part of transmission planning, PJM creates an annual forecast of electricity load growth in the PJM footprint. Additionally, the Maryland PSC is increasingly directing the utilities to perform capacity adequacy planning. PPRP's last electricity demand forecast was conducted in 2006 and due to the forecasting functions being taken over by the other entities, in the future, PPRP will rely on the forecasts being prepared by the utilities and PJM. This appendix provides the results of the most recent (2008) PJM load forecast of electric energy consumption in Maryland.

Methodological Summary

PJM conducts load forecasts by PJM zone (see Figure C-1), which are based largely on the boundaries of the primary electric company in the region. Maryland is a part of four separate PJM zones, only one of which is entirely located within the state boundaries.

- ***APS*** *– this is a large zone encompassing all of Allegheny Power's utility services geographic area, which includes West Penn Power Company (Pennsylvania), Monongahela Power Company (West Virginia), and the Potomac Edison Company (Western Maryland, Virginia, and West Virginia). Maryland is only a very small portion of this zone; according to Allegheny Power's end-use electricity sales data, 15 percent of utility electricity sales in 2008 were in Maryland.*
- ***BGE*** *– this zone consists of the Baltimore Gas & Electric service area. This is the only zone entirely within the state.*
- ***DPL*** *– this zone coincides with Delmarva Power's geographic service area covering all of Delaware and the Eastern Shore region.*

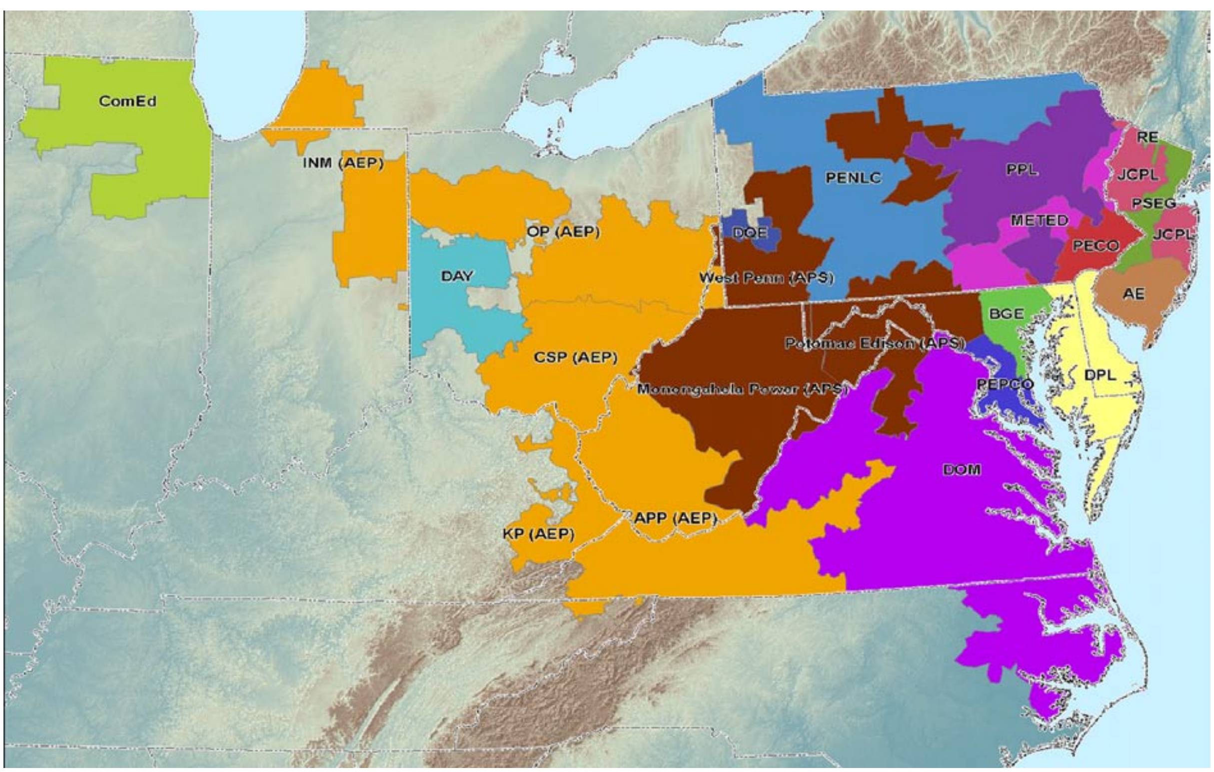
- ***Pepco*** *– this zone includes all of Potomac Electric Company's geographic service area, which includes the District of Columbia and Montgomery and Prince George's counties, along with southern Maryland.*

PJM collects hourly load data for each electric distribution company on its system. The hourly load data is used for operational analysis, to derive seasonal load profiles and weather normalization factors, and for preparing the various charts and tables contained in the PJM Load Forecast Report. PJM uses econometric multiple regression models to estimate the daily peak load for each of the zones. Economic drivers can be included at the national, state, or metropolitan level. PJM uses Gross Metropolitan Product as its base economic statistic and demographic data. For the peak demand forecast, the hourly load data is the dependent variable and for the energy forecast, the dependent variable is daily energy consumption.

Energy Consumption Projections

The effects of the economic recession resulted in a slowdown in electricity load growth between 2008 and 2009. Total electricity consumption in PJM for 2008 was 716,198 GWh, and in 2009, it is projected to be 712,236 GWh. Many (though not all) PJM zones experienced negative growth in electricity consumption between 2008 and 2009. The largest drop in consumption is expected in the western zones, with the PJM Western Region experiencing a 1.3 percent drop in electricity use between 2008 and 2009. The Maryland zones, however, are not expected to experience negative growth, though as can be seen in Table C-1, there is a slowing of demand growth in all but the Pepco zone (which contains the District of Columbia).

Figure C-1 PJM Load Forecast Zones



Source: PJM Load Forecast Report, January 2009.

PJM does not expect this situation to continue into 2010, but projects an economic rebound that will return annual load growth to the projected average annual growth rate of 1.6 percent for the next 10 years. PJM projects total consumption at 719,433 GWh in 2010, exceeding the 2008 level. BGE, in particular, does not see very much of a decrease in electricity demand. PJM expects the BGE zone to have accelerated load growth as a result of the U.S. Military Base Realignment and Closure Program.

Table C-1 PJM Energy Consumption Forecast by Zone

Electricity Consumption (GWh)					
Year	**APS**	**BGE**	**DPL**	**Pepco**	**Total**
2007*	51,040	34,967	19,730	32,883	138,620
2008	48,864	34,402	19,094	32,230	134,590
2009	49,309	34,928	19,136	33,063	136,436
2010	50,176	35,520	19,230	33,391	138,317
2011	51,468	36,442	19,735	33,951	141,596
2012	52,674	37,054	20,397	34,655	144,780
2014	53,882	37,944	21,161	35,404	148,391
2016	55,141	39,308	21,805	36,241	152,495
2018	56,155	40,450	22,401	36,913	155,919
2020	57,539	41,814	23,167	37,791	160,311
Electricity Consumption Average Annual Growth Rates					
2007-2009	(1.7%)	(0.1%)	(1.5%)	0.3%	(0.8%)
2008-2009	0.9%	1.5%	0.2%	2.6%	1.3%
2009-2015	1.7%	1.7%	1.9%	1.3%	1.7%
2015-2020	1.1%	1.6%	1.5%	1.1%	1.3%
2009-2020	1.4%	1.6%	1.7%	1.2%	1.5%

*Data for 2007 are estimates from PJM 2008 Load Forecast Report.
Source: PJM 2009 Load Forecast Report, January 2009.

Peak Load Growth Projections

PJM reports that the weather-normalized summer peak for 2008 was 136,315 MW and the projection for the 2009 peak is 134,428 MW, a 1.4 percent reduction. In 2010, load growth is expected to return to the projected average of 1.7 percent for the next 10 years, with the summer peak reaching 2008 levels again in 2011. The effects of the recession can be seen in Figure C-2, which plots summer peak load growth from the 2008 and 2009 forecasts for the BGE zone.

Though PJM does not disaggregate the forecast to the state level, it does report some state-level data in the transmission expansion plan. PJM reported in its 2008 Regional Transmission Expansion Plan that peak summer load growth rates in zones within Maryland and Washington, D.C. are expected to range from 0.9 percent to 2.0 percent over the 10-year period through 2018, and peak winter load growth rates are expected to range between 0.6 percent and 1.4 percent over the 10-year period through 2017/2018. This is consistent with the zonal growth rates from the load forecast.

Table C-2 PJM Historical Energy

PJM RTO Unrestricted Load (GWh)		
Year	**Energy (GWh)**	**Growth Rate**
2003	675,439	--
2004	689,523	2.0%
2005	712,246	3.3%
2006	694,971	(2.4%)
2007	724,454	4.2%
2008	714,108	(1.4%)
2009*	712,236	(0.3%)
Average Annual Growth Rate		
2003-2008		1.2%
2003-2009		0.9%

*Data from 2009 is projected energy consumption from the 2009 Load Forecast.
Source: PJM Hourly Unrestricted Load 1998-2008, January 28, 2009.

Table C-3 PJM Summer Peak Load Forecast by Zone (MW)

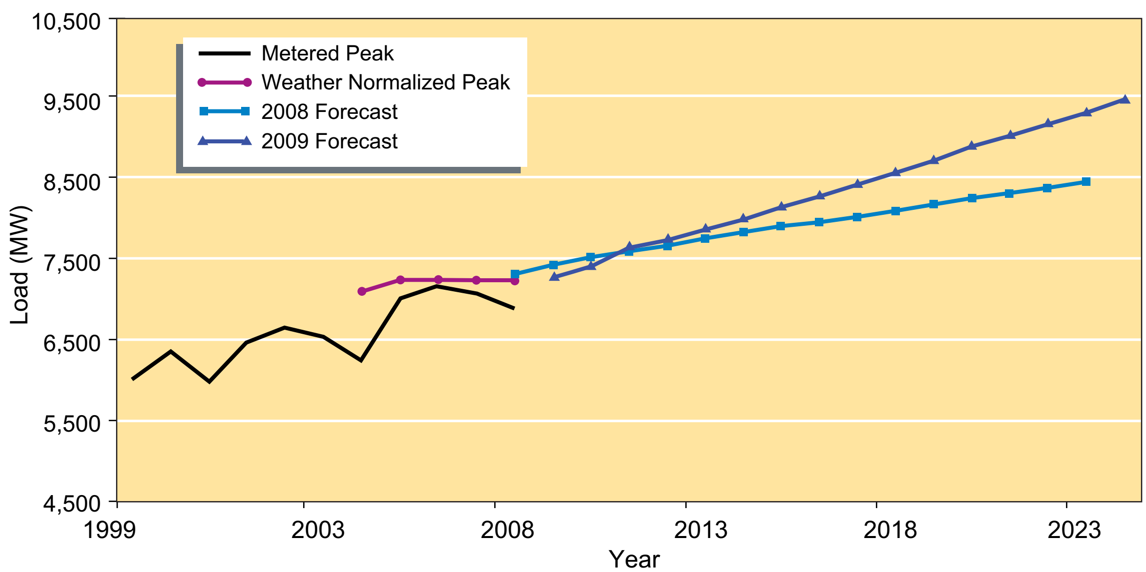
Year	APS	BGE	DPL	Pepco	Total
2008	8,432	7,270	4,010	6,930	26,642
2009	8,538	7,303	3,972	6,960	26,773
2010	8,704	7,446	4,002	7,026	27,178
2015	9,487	8,176	4,554	7,512	29,729
2020	10,038	8,913	4,969	7,911	31,831

Source: PJM 2009 Load Forecast Report, January 2009.

Table C-4 PJM Historic Summer Peak Load (MW)

Year	APS	BGE	DPL	Pepco	Total	Change in Total Peak Load
2003	8,373	6,822	3,811	6,277	25,283	--
2004	8,348	6,922	3,810	6,391	25,471	0.7%
2005	8,630	7,160	4,070	6,810	26,670	4.7%
2006	8,550	7,350	4,100	6,920	26,920	0.9%
2007	8,620	7,260	4,130	6,950	26,960	0.1%

Figure C-2 BGE Zone Weather Normalize Summer Peak Load Forecast



Source: PJM Load Forecast Report, January 2009.

Appendix D – Determinants of Electricity Demand Growth in Maryland

Introduction

PPRP has historically conducted a program of independent electric load forecasts as part of its efforts to both monitor the adequacy of future power supplies and to independently evaluate the potential for excess generating capacity. With the restructuring of the retail electric industry in Maryland brought about by the enactment of the Maryland Electric Customer Choice and Competitive Act of 1999, the preparation of load forecasts (energy sales and peak demands) for the individual investor-owned electric utilities operating within Maryland is not sufficient to provide the information required to assess the adequacy of planned supply.

Under restructuring, the primary issues relating to power supply affecting Maryland consumers are the adequacy of generating capacity and of transmission system capacity. The issue of excess generating capacity was of great importance under historical regulatory arrangements since captive ratepayers shouldered the cost burden of the excess generating capacity. Under restructuring, ratepayers no longer bear the cost of excess capacity, but certain non-monetary costs (e.g., socioeconomic and environmental impacts) are potentially imposed on Maryland ratepayers from excess generating capacity. To assess and monitor the sufficiency of generation and transmission capacity, PPRP has modified its load forecasting program. Rather than focusing on the individual electric utilities serving consumers in the state, PPRP now forecasts energy requirements and peak demands for the state as a whole and for the various regions within the state.

The PPRP forecast studies, including those historically performed for the service areas of the individual utilities as well as the state-wide forecast, use economic theory as the organizing principle to model the demand for electricity, and rely on econometric methods for estimation and projection. The data that are used to run these models, both historical and projected, are comprised of variables assumed a priority to significantly affect the demand for electricity. Economic variables include income, the price of electricity, and employment; non-economic variables include population and weather. Historical information is required for estimation purposes, while projected data are necessary to forecast the demand for power econometrically.

This appendix provides an overview of the basic theoretical foundations upon which these forecast studies rest, and an analysis of the trends of some of the economic and non-economic determinants of the demand for electricity. The Maryland data presented here have been obtained from the Maryland Department of Planning, the Bureau of Economic Analysis of the U.S. Department of Commerce, and the Bureau of Labor Statistics of the U.S. Department of Labor. For comparison, some national data are also included. The national data were obtained from the U.S. Departments of Commerce and Labor.

This appendix is composed of five sections. The following section presents a brief discussion of the theoretical foundations used for modeling the demand for electricity econometrically. This section sets the stage for the rest of the appendix, which examines economic

Table D-1 Principal Regions in Maryland

Region	Counties	Predominant Electric Distribution Utility
Baltimore	Anne Arundel	Baltimore Gas and Electric Company
	Baltimore	
	Baltimore City	
	Carroll	
	Frederick	
	Harford	
	Howard	
Washington Suburban	Montgomery	Potomac Electric Power Company
	Prince George's	
Southern Maryland	Calvert	Southern Maryland Electric Cooperative
	Charles	
	St. Mary's	
Western Maryland	Allegany	Potomac Edison Company
	Garrett	
	Washington	
Eastern Shore	Caroline	Delmarva Power and Choptank Electric
	Cecil	
	Dorchester	
	Kent	
	Queen Anne's	
	Somerset	
	Talbot	
	Wicomico	
	Worcester	

and demographic trends for Maryland by region. For purposes of presentation, the state has been divided into five regions, as shown in Table D-1. These regions correspond to the regional definitions used in the PPRP state-wide forecast, but differ from those used by the Maryland Department of Planning. The section covering the theoretical foundations is followed by a section discussing trends in per capita income, which, in turn, is followed by a section discussing trends in employment. Trends in population and the number of households follow the employment section. The final section presents a brief summary.

Theoretical Foundations for Econometrically Modeling the Demand for Electricity

The PPRP forecast studies use the economic theory of demand as the organizing principle to econometrically model the demand for electricity. The total demand for any good or service, including electricity, is simply the sum of the demands of the individual consumers in the market. The portion of market demand for residential use of electricity is driven by factors to which individual residential consumers are sensitive. Similarly, for the commercial and industrial sectors of the market demand for electricity, the factors affecting demand are those to which producers are sensitive.

In the case of residential demand, electricity forms part of the basket of goods and services purchased by the consumer. The residential demand for electricity is assumed to result from the exercise of choice by which the consumer maximizes his welfare subject to a budget constraint. Consumer demand for electricity is taken to be a function of its price, consumer income, weather, and the price of related commodities (i.e., substitutes and complements). It is important to note that electricity, in and of itself, conveys no benefits to the consumer. Rather, the consumer benefits from the services of the stock of appliances that require electricity. These services include space conditioning, refrigeration, cooking, clothes washing and drying, and numerous other services and functions. Consequently, the demand for electricity can be appropriately viewed as a derived demand; that is, it results from the demand for the services provided by electricity-consuming appliances.

For commercial and industrial customers, electricity is a factor of production, i.e., an input. In the PPRP forecast studies, the demand for electricity is assumed to result from decisions made by the producer to maximize profits. For the profit-maximizing producer, demand for a commodity (including electricity) is driven by its price, the price of related inputs, and the level of output. Producer demand for electricity is also driven by other factors, including weather.

Both the residential and non-residential demand for electric power are discussed above in terms of the individual consumer or producer. The market demand for electric power, for example, in Maryland or within regions in Maryland, is also dependent on the number of consumers (households) and the level of goods and services produced in the region. Residential demand is, therefore, forecasted on a per customer basis, which, when multiplied by the projected number of residential customers, provides a forecast of total residential demand. Commercial and industrial electric sales are projected per employee, which is then multiplied by the number of forecasted employees to project total commercial and industrial demand for electricity. Employment is used in lieu of, and as a proxy for, output since no satisfactory time series of output data are available at a suitably disaggregated level.

Per Capita Income Trends

Income is an important determinant of the residential demand for electricity, and changes in income will affect the quantity of electricity purchased. Changes in income affect electric power consumption in two ways. First, a change in income will induce a change in the intensity of use of the existing stock of electricity-consuming appliances. Second, an income change will induce changes in the stock of electricity-consuming appliances. As income changes, therefore, the demand for electricity will rise or fall. The PPRP forecast studies demonstrate a positive and, typically, statistically significant relationship between income and the residential demand for electricity.

The PPRP forecast studies (the historical service area forecasts as well as the state-wide forecasts conducted following industry restructuring) use real (i.e., inflation adjusted) per capita income as an explanatory variable. Real per capita income figures are reported in Table D-2 for the Maryland regions defined in Table D-1. Table D-2 summarizes historical and projected data as well as average annual growth rates for the period 1990 through 2015. As shown by the historical data, all regions within the state, with the exception of Western Maryland, experienced a substantial slowing in the growth of real per capita income during the 2000 to 2005 period in comparison to the 1990 to 2000 period. For the state as a whole, growth in real per capita income declined to 1.73 percent per year between 2000 and 2005, compared to an average annual growth rate of 1.90 percent between 1990 and 2000. The projections for the 2005 to 2015 period are generally lower than the rates experienced during the 1990 to 2000 period and comparable to rates during the 2000 to 2005 period. Between 2005 and 2015, real per capita income is expected to increase at an average annual rate of 1.70 percent for the state as a whole. The most rapid increase in real per capita income is expected in the Western Maryland region (2.14 percent per year), with the slowest growth over the 2005 to 2015 period projected for the Washington suburban region (1.50 percent per year).

Table D-2 Historical and Projected Per Capita Income for Maryland, 1990-2015 (Dollars)

					Annual Rate of Growth		
Region	**1990**	**2000**	**2005**	**2015**	**1990-2000**	**2000-2005**	**2005-2015**
State of Maryland	$28,389	$34,261	$37,331	$44,174	1.90%	1.73%	1.70%
Baltimore	$27,082	$33,281	$36,692	$43,778	2.08%	1.97%	1.78%
Washington Suburban	$33,172	$38,987	$42,150	$48,903	1.63%	1.57%	1.50%
Southern Maryland	$24,848	$30,375	$31,998	$39,385	2.03%	1.05%	2.10%
Western Maryland	$19,485	$23,399	$25,305	$31,276	1.85%	1.58%	2.14%
Eastern Shore	$22,714	$27,371	$29,727	$35,949	1.88%	1.66%	1.92%

Prepared by the Maryland Department of Planning, Planning Data Services, February 2009.
Historical data, 1970 - 2000 from the U.S. Bureau of Economic Analysis.

Employment Trends

The non-residential demand for electricity is largely driven by the level of output. The PPRP forecast studies, however, do not use output as an explanatory variable because quarterly output data at the county level are not available on a consistent basis. Hence, a proxy for output must be used. Non-farm employment has typically been relied upon for this purpose. It is a sound alternative and it is not subject to data consistency problems.

Table D-3 Historical and Projected Employment for Maryland, 1990–2015 (Thousands)

	Total Labor Force					Annual Rate of Growth		
Region	1990	2000	2005	2010	2015	1990-2000	2000-2005	2005-2015
State of Maryland	2,639,896	2,769,525	2,892,140	3,027,210	3,193,640	0.48%	0.87%	1.00%
Baltimore	1,258,417	1,291,461	1,331,770	1,384,210	1,442,500	0.26%	0.62%	0.80%
Washington Suburban	974,337	1,015,394	1,060,960	1,109,090	1,172,420	0.41%	0.88%	1.00%
Southern Maryland	125,680	150,356	169,250	182,490	200,450	1.81%	2.40%	1.71%
Western Maryland	104,508	110,562	114,600	120,090	128,050	0.56%	0.72%	1.12%
Eastern Shore	176,954	201,752	215,560	231,330	250,220	1.32%	1.33%	1.50%

Source: Maryland Department of Planning, Planning Data Services, February 2009.

Employment data by major employment sector are reported in Table D-3.

Table D-3 reports historical employment for Maryland for 1990 and 2000 and projected employment for 2005, 2010, and 2015. As shown in Table D-3, every region of the state is expected to experience employment growth. Growth is projected to be most rapid in the Southern Maryland region and slowest in Baltimore, which is consistent with recent historical relationships. For the state as a whole, average annual growth in employment for the 2005 to 2015 period is expected to be slightly higher than the growth over the 2000 to 2005 period (1.00 percent per year compared to 0.87 percent). Growth in employment for all of the regions in Maryland during the 2005 to 2015 period is projected to be higher than experienced during the 1990's, with the exception of Southern Maryland and Western Maryland.

The current economic downturn is likely to greatly affect employment, as well as energy consumption, in 2009 and 2010. Maryland's unemployment rate rose from 3.7 percent in February 2008 to 6.7 percent in February 2009. Manufacturing output is likely to decline in Maryland as well, with a resultant energy usage by commercial and industrial customers below prior expectations.

Population Trends

Population is an important causal variable in the PPRP electricity consumption forecast models because population trends are used to project the number of residential customers. Two demographic concepts closely related to population are the number of households and average household size. These concepts can be important since the number of households affects the number of residential customers purchasing electricity, and changes in average household size can affect usage per customer. Population growth and the rate of household formation are closely related, and both affect the residential use of electricity. Increases in population lead to increases in the number of households (and hence residential customers) although rates of change need not coincide due to changes in the size of households. Population and household data are reported in Tables D-4 and D-5.

Population data at regional and state levels are reported in Table D-4. The table summarizes historical and projected data, as well as average annual rates of growth for the period 1990 through 2015. The rates of growth in population have been positive since 1990 for every region of Maryland. Between 1990 and 2005, population growth in Maryland has been 1.03 percent per year on average. The growth in population for the state is projected to slow to approximately 0.71 percent between 2005 and 2010, before rising again to 1.04 percent from 2010 to 2015. The pattern of slowing growth from 1990 to 2005 for the state as a whole also characterizes the expected pattern of growth in four of the five separate regions. The exception is Western Maryland, where growth in population increased at an average annual rate of 0.54 percent between 1990 and 2005 compared to an expected average annual growth of 0.88 percent between 2005 and 2015. Western Maryland population represents about 4 percent of total state population. Consequently, the population growth rate trend for this region does not significantly affect the trend expected for the state as a whole.

Table D-4 Historical and Projected Population for Maryland, 1990-2015 (Thousands)

					Annual Rate of Growth		
Region	1990	2000	2005	2015	1990-2000	2000-2005	2005-2015
State of Maryland	4,781	5,296	5,577	6,087	1.03%	1.04%	0.88%
Baltimore	2,348	2,512	2,602	2,780	0.68%	0.71%	0.66%
Washington Suburban	1,636	1,870	1,989	2,180	1.35%	1.24%	0.92%
Southern Maryland	229	281	320	376	2.10%	2.58%	1.63%
Western Maryland	224	237	243	266	0.53%	0.55%	0.88%
Eastern Shore	344	396	423	485	1.42%	1.35%	1.37%

Prepared by the Maryland Department of Planning, Planning Data Services, May 2004.

Projected population growth in the Baltimore is expected to become the lowest in the state between 2005 and 2015 due to the expected change in growth in Western Maryland. Between 1995 and 2005, population in the Baltimore region grew at an average annual rate of 0.69 percent; the growth rate is projected to remain similar over the 2005 to 2015 period averaging about 0.66 percent per year.

As suggested by the discussion of population growth in Western Maryland and the Baltimore region, the rates of growth in population are uneven across the state. Historically, the largest growth rates were reported for Southern Maryland and the smallest rates for Western Maryland. Between 1990 and 2000, the population growth rate for Southern Maryland was approximately four times that of Western Maryland. While disparities are expected to continue, it is anticipated that there will be a narrowing of the growth rate differentials over the 2005 to 2015 period compared to the earlier period.

Table D-5 Historical and Projected Number of Households and Average Size of Households in Maryland, 1990-2015

					Annual Rate of Growth		
Region	1990	2000	2005	2015	1990-2000	2000-2005	2005-2015
NUMBER OF HOUSEHOLDS (THOUSANDS)							
State of Maryland	1,749	1,981	2,098	2,194	1.25%	1.16%	1.09%
Baltimore	868	959	997	1,038	1.00%	0.79%	0.93%
Washington Suburban	593	681	728	759	1.40%	1.35%	1.05%
Southern Maryland	75	98	112	122	2.63%	2.83%	1.94%
Western Maryland	85	91	95	98	0.69%	0.91%	0.98%
Eastern Shore	129	153	165	177	1.73%	1.62%	1.58%
AVERAGE HOUSEHOLD SIZE							
State of Maryland	2.67	2.61	2.59	2.53	-0.24%	-0.13%	-0.22%
Baltimore	2.64	2.55	2.54	2.47	-0.35%	-0.11%	-0.28%
Washington Suburban	2.71	2.70	2.68	2.64	-0.05%	-0.13%	-0.14%
Southern Maryland	2.97	2.83	2.80	2.71	-0.50%	-0.24%	-0.31%
Western Maryland	2.52	2.44	2.40	2.36	-0.34%	-0.34%	-0.14%
Eastern Shore	2.58	2.51	2.47	2.42	-0.29%	-0.29%	-0.21%

Prepared by the Maryland Department of Planning, Planning Data Services, May 2004. Projections for the Baltimore Region based on Round 6A from the Baltimore Metropolitan Council of Government's Cooperative Forecasting Committee. Projections for the Washington Suburban and Southern Maryland Regions based on Round 6.4 of the Metropolitan Council of Government's Cooperative Forecasting Committee.

Household data for the state and for regions within the state are shown in Table D-5. The table shows a summary of historical and projected data, as well as average annual rates of growth for the period 1990 through 2015. Average annual growth for the state in the number of households was 1.25 percent between 1990 and 2000, declined to 1.16 percent between 2000 and 2005, and is expected to further decline to approximately 1.09 percent through 2015. Southern Maryland is expected to experience the greatest slowing of growth, from 2.58 percent between 2000 and 2005 to 1.94 percent from 2005 to 2015. Nevertheless, Southern Maryland is projected to have the most rapid growth in the number of households in the state between 2005 and 2015.

Since 1990, household size in each of the five Maryland regions has been declining, and the decline is forecasted to continue through 2015. For the state, the average household size was 2.67 people in 1990, declined to 2.61 in 2000 (representing an average rate of decline of about 0.24 percent per year) and further declined to 2.59 in 2005 (a decline of 0.13 percent per year, on average, compared to 2000). The rate of decline is expected to be approximately 0.22 percent per year between 2005 and 2015. The largest declines in average household size are projected for Southern Maryland and the smallest for Western Maryland.

Summary

This appendix provides a review of the theoretical foundations used for modeling the demand for electricity econometrically in the PPRP forecast studies. In doing so, emphasis is placed on some of the key determinants of the demand for electric power. The determinants of demand are classified into residential and non-residential, as well as into economic and non-economic for purposes of exposition. Per capita income is an explanatory economic variable that influences the residential demand for electricity; population, the number of households, and average household size are non-economic explanatory variables affecting residential electricity consumption. This appendix also shows trends in employment, which affect the non-residential demand for electricity. Selected data on these determinants of demand are reported and trend analyses presented. The broad conclusion to emerge from these trends is that the demand for electricity should continue to grow in Maryland.